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Volume 2

Design of Thermal Power Facilities

Book 5/12

« Oil Fuel Handling Facility »

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List of Acronyms/Abbreviations

API	American Petroleum Institute
AS	Australia Standard
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing
AUT	Automatic Ultrasonic Testing
BS	British Standard
CFR	Code of Federal Regulations
CHPS	Casing Head Petroleum Spirit
CPI	Corrugated Plate Interceptor
CSA	Canadian Standards Association
ESD	Emergency Shut Down
FXS	Foreign Exchange Subscriber
GPR	Ground Potential Rise
IP	Internet Protocol
ISO	International Organization for Standardization
JSW	Jumbo Switch
JIS	Japanese Industrial Standard
LPG	Liquefied Petroleum Gas
MAOP	Maximum Allowable Operating Pressure
MIG	Metal Inert Gas Welding
MSS	Manufacturers Standardization Society
MT	Magnaflux Testing
NACE	National Association of Corrosion Engineers
NFPA	National Fire Protection Association
NGL	Natural Gas Liquid
OEC	Outer Electricity supply Cabinet
PLC	Programmable Logic Controller
PHMSA	Pipeline and Hazardous Materials Safety Administration
ROW	Right Of Way
RTU	Remote Terminal Unit
RT	Radiographic Testing
SCADA	Supervisory Control and Data Acquisition
SMYS	Specified Minimum Yield Strength
TFL	Through Flow Line
TIG	Tungsten Inert Gas Welding
UT	Ultrasonic Testing
VLCC	Very Large Crude Carrier
VOC	Volatile Organic Compound
WPS	Welding Procedure Specification

Chapter-1. Comparison between Technical Regulation and Technical Guideline of oil fuel handling facility

The article number of this guideline is shown in the Table-1 contrasted technical regulation with technical guideline for easy understanding.

Table- 1: Comparison between Technical Regulation and Technical Guideline of oil fuel handling facility

Technical Regulation		Technical Guideline	
Article 59.	General provision	Article 59.	General provision
-1.	General provision	-1.	General provision
Article 60.	Oil unloading facility	Article 60.	Oil unloading facility
-1.	Mooring equipment	-1.	Mooring equipment
-2.	Loading facility	-2.	Loading facility
-3.	Fence	-3.	Fence
-4.	Purge equipment	-4.	Purge equipment
-5.	Sign	-5.	Sign
Article 61.	Oil metering facility	Article 61.	Oil metering facility
-1.	Location of metering facility	-1.	Location of metering facility
-2.	Testing procedure of metering facility	-2.	Testing procedure of metering facility
-3.	Sampling	-3.	Sampling
-4.	Future installation	-4.	Future installation
Article 62.	Oil pipeline	Article 62.	Oil pipeline
-1.	Monitoring equipment	-1.	Monitoring equipment
-2.	Shut-off valve	-2.	Shut-off valve
-3.	Indication of valve opening status	-3.	Indication of valve opening status
-4.	Leakage detector	-4.	Leakage detector for oil receiving pipeline
-5.	Location of leakage detector	-5.	Location of leakage detector
-6.	Seismic sensor	-6.	Seismic sensor
-7.	Warning equipment	-7.	Warning equipment
-8.	Reporting equipment	-8.	Reporting equipment
-9.	Location of reporting equipment	-9.	Location of reporting equipment
-10.	Reporting facility	-10.	Reporting facility
Article 63.	Oil pumping facility	Article 63.	Oil pumping facility
-1.	Pumping unit	-1.	Pumping unit
-2.	Other pumps	-2.	Other pumps
Article 64.	General provision	Article 64.	General provision
-1.	General provision for oil transportation	-1.	General provision for oil transportation facility

Technical Regulation		Technical Guideline	
	facility		
Article 65.	Material of oil pipeline	Article 65.	Material of oil pipeline
-1.	Material for oil pipeline	-1.	Material for oil pipeline
Article 66.	Structure of oil pipeline, etc.	Article 66.	Structure of oil pipeline, etc.
-1.	Structure of oil pipeline	-1.	Structure of oil pipeline
-2.	Regulation	-2.	Regulation
-3.	Allowable stress	-3.	Allowable stress
-4.	Applicable standard	-4.	Applicable standard
Article 67.	Expansion measure for oil pipeline	Article 67.	Expansion measure for oil pipeline
-1.	Harmful expansion	-1.	Harmful expansion
Article 68.	Joints of oil pipeline, etc.	Article 68.	Joints of oil pipeline, etc.
-1.	Joint of pipeline	-1.	Joint of pipeline
-2.	Measure for oil leakage	-2.	Measure for oil leakage
Article 69.	Welding of oil pipeline, etc.	Article 69.	Welding of oil pipeline, etc.
-1.	Welding of pipeline	-1.	Welding of pipeline
-2.	Welding equipment and consumables	-2.	Welding equipment and consumables
Article 70.	Anti-corrosion coating of oil pipeline	Article 70.	Anti-corrosion coating of oil pipeline
-1.	Protection for pipeline underground or on seabed	-1.	Protection for pipeline underground or on seabed
-2.	Protection for pipeline on the land or sea	-2.	Protection for pipeline on the land or sea
Article 71.	Electric protection of oil pipeline, etc.	Article 71.	Electric protection of oil pipeline, etc.
-1.	Protection for pipeline underground or on seabed	-1.	Protection for pipeline underground or on seabed
-2.	Protection for pipeline on the land or sea	-2.	Protection for pipeline on the land or sea
Article 72.	Heating and insulation for oil pipeline	Article 72.	Heating and insulation for oil pipeline
-1.	Space heating	-1.	Space heating
Article 73.	Installation site of oil pipeline	Article 73.	Installation site of oil pipeline
-1.	Installation on the ground	-1.	Installation on the ground
Article 74.	Underground installation of oil pipeline	Article 74.	Underground installation of oil pipeline
-1.	Underground installation	-1.	Underground installation
Article 76.	Oil pipeline, etc. installed buried under rail road	Article 76.	Oil pipeline, etc. installed buried under rail road
-1.	Installation buried under the rail road	-1.	Installation buried under the rail road
Article 77.	Oil pipeline, etc. installed buried in the regional river conservation	Article 77.	Oil pipeline, etc. installed buried in the regional river conservation
-1.	Installation buried in the regional river	-1.	Installation buried in the regional river

Technical Regulation		Technical Guideline	
	conservation		conservation
Article 78.	Onshore installation oil pipeline, etc.	Article 78.	Onshore installation oil pipeline, etc.
-1.	Installation above the ground	-1.	Installation above the ground
Article 79	Subsea installation of oil pipeline, etc.	Article 79	Subsea installation of oil pipeline, etc.
-1.	Installation on the seabed	-1.	Installation on the seabed
Article 80.	Offshore installation of oil pipeline, etc.	Article 80.	Offshore installation of oil pipeline, etc.
-1.	Installation in the sea	-1.	Installation in the sea
Article 81.	Oil pipeline, etc. installation across the road	Article 81.	Oil pipeline, etc. installation across the road
-1.	Installation across the load	-1.	Installation across the load
Article 82.	Oil pipeline, etc. installation across the rail road	Article 82.	Oil pipeline, etc. installation across the rail road
-1.	Installation across the rail road	-1.	Installation across the rail road
Article 83.	Oil pipeline, etc. installation across the river	Article 83.	Oil pipeline, etc. installation across the river
-1.	Installation across the river	-1.	Installation across the river
-2.	Sheath tube	-2.	Sheath tube
-3.	Piping cover	-3.	Piping cover
Article 84.	Measure for leakage and spread of oil pipeline, etc.	Article 84.	Measure for leakage and spread of oil pipeline, etc.
-1.	Measure for leakage	-1.	Measure for leakage
Article 85.	Prevention of accumulation of flammable vapor from oil pipeline, etc.	Article 85.	Prevention of accumulation of flammable vapor from oil pipeline, etc.
-1.	Flammable vapor	-1.	Flammable vapor
Article 86.	Installation in a place where there might be uneven settlement, etc.	Article 86.	Installation in a place where there might be uneven settlement, etc.
-1.	Uneven settlement	-1.	Uneven settlement
Article 87.	Oil pipeline connection with bridge	Article 87.	Oil pipeline connection with bridge
-1.	Connection with bridge	-1.	Connection with bridge
Article 88.	Non destructive test of oil pipeline, etc.	Article 88.	Non destructive test of oil pipeline, etc.
-1.	RT	-1.	RT
-2.	MT, PT	-2.	MT, PT
Article 89.	Pressure test of oil pipeline, etc.	Article 89.	Pressure test of oil pipeline, etc.
-1.	Pressure test	-1.	Pressure test
Article 90.	Operation monitoring device for oil pipeline, etc.	Article 90.	Operation monitoring device for oil pipeline, etc.

Technical Regulation		Technical Guideline	
-1.	Monitoring equipment	-1.	Monitoring equipment
-2.	Warning equipment	-2.	Warning equipment
Article 91.	Safety controller for oil pipeline, etc.	Article 91.	Safety controller for oil pipeline, etc.
-1.	Safety controller	-1.	Safety controller
Article 92.	Pressure relief device for oil pipeline, etc.	Article 92.	Pressure relief device for oil pipeline, etc.
-1.	Pressure relief device	-1.	Pressure relief device
-2.	Strength of pressure relief device	-2.	Strength of pressure relief device
-3.	Capacity of pressure relief device	-3.	Capacity of pressure relief device
Article 93.	Leakage detector, etc. for oil pipeline, etc.	Article 93.	Leakage detector, etc. for oil pipeline, etc.
-1.	Leakage detector	-1.	Leakage detector
Article 94.	Emergency shut-off valve for oil pipeline, etc.	Article 94.	Emergency shut-off valve for oil pipeline, etc.
-1.	Emergency shut-off valve	-1.	Emergency shut-off valve
-2.	Function of shut-off valve	-2.	Function of shut-off valve
-3.	Indication of open and close	-3.	Indication of open and close
-4.	Installation in the box	-4.	Installation in the box
-5.	Specified person	-5.	Specified person
Article 95.	Oil removal measure for oil pipeline, etc.	Article 95.	Oil removal measure for oil pipeline, etc.
-1.	Removal of oil	-1.	Removal of oil
Article 96.	Seismic sensor, etc. for oil pipeline, etc.	Article 96.	Seismic sensor, etc. for oil pipeline, etc.
-1.	Seismic sensors	-1.	Seismic sensors
Article 97.	Notification facility of oil pipeline, etc.	Article 97.	Notification facility of oil pipeline, etc.
-1.	Report facility	-1.	Report facility
-2.	Emergency reporting facility	-2.	Emergency reporting facility
-3.	Location of reporting facility	-3.	Location of reporting facility
Article 98.	Alarm facility of oil pipeline, etc.	Article 98.	Alarm facility of oil pipeline, etc.
-1.	Warning facility	-1.	Warning facility
Article 99.	Firefighting facility for oil pipeline, etc.	Article 99.	Firefighting facility for oil pipeline, etc.
-1.	Fire extinguishing equipment	-1.	Fire extinguishing equipment
Article 100.	Chemical fire engine for oil pipeline, etc.	Article 100.	Chemical fire engine for oil pipeline, etc.
-1.	Chemical fire engine	-1.	Chemical fire engine
Article 101.	Back-up power for oil pipeline, etc.	Article 101.	Back-up power for oil pipeline, etc.
-1.	Reserve power source	-1.	Reserve power source
Article 102.	Grounding, etc. for safety of oil pipeline,	Article 102.	Grounding, etc. for safety of oil pipeline, etc.

Technical Regulation		Technical Guideline	
	etc.		
-1.	Grounding system	-1.	Grounding system
Article 103.	Isolation of oil pipeline, etc.	Article 103.	Isolation of oil pipeline, etc.
-1.	Isolation of pipeline	-1.	Isolation of pipeline
-2.	Insert for isolation	-2.	Insert for isolation
-3.	Arrester	-3.	Arrester
Article 104.	Lightning protection system for oil pipeline, etc.	Article 104.	Lightning protection system for oil pipeline, etc.
-1.	Lighting protection	-1.	Lighting protection
Article 105.	Indication, etc. for oil pipeline, etc.	Article 105.	Indication, etc. for oil pipeline, etc.
-1.	Location mark	-1.	Location mark
Article 106.	Operation test of safety facility for oil pipeline, etc.	Article 106.	Operation test of safety facility for oil pipeline, etc.
-1.	Safety equipment	-1.	Safety equipment
Article 107.	Pig handling equipment for oil pipeline, etc.	Article 107.	Pig handling equipment for oil pipeline, etc.
-1.	Pig handling equipment	-1.	Pig handling equipment
Article 108.	General provision of oil storage facility	Article 108.	General provision of oil storage facility
-1.	General provision of oil storage facility	-1.	General provision of oil storage facility
Article 109.	Oil storage tank	Article 109.	Oil storage tank
-1.	Outdoor oil storage tank	-1.	Outdoor oil storage tank
-2.	Specific outdoor oil storage tank	-2.	Specific outdoor oil storage tank
-3.	Underground storage tank	-3.	Underground storage tank
-4.	Indoor oil storage tank	-4.	Indoor oil storage tank
-5.	Calculation of tank capacity	-5.	Calculation of tank capacity
Article 110.	Pipeline of oil storage tank	Article 110.	Pipeline of oil storage tank
-1.	Pipeline of oil storage tank	-1.	Pipeline of oil storage tank
Article 111.	Changeover valve, etc. of oil storage tank	Article 111.	Changeover valve, etc. of oil storage tank
-1.	Changeover valve, etc. of oil storage tank	-1.	Changeover valve, etc. of oil storage tank
Article 112.	Oil receiving opening of oil storage tank	Article 112.	Oil receiving opening of oil storage tank
-1.	Oil receiving port	-1.	Oil receiving port
Article 113.	Safety measure for oil terminal	Article 113.	Safety measure for oil terminal
-1.	Controlled area	-1.	Controlled area
-2.	Prevention of oil flow-out	-2.	Prevention of oil flow-out

Chapter-2. Each Items of Guideline

Article 59. General provision

Article 59-1. General provision

1. A variety of fuels have been used in thermal power plants according to the environmental measure and fuel situation. They are divided into light oil, heavy oil, crude oil and naphtha, though its property is greatly different in cases even the same specification. In addition, NGL (natural gasoline) and residual oil are used and use of methanol has been considered. Among these, light oil has been used for ignition and startup of boiler with relatively low fuel consumption or fuel oil for auxiliary boiler because in the easy handling. Also, heavy oil is classified into type-1, type-2 and type-3 and known as A-heavy-oil, B-heavy oil and C-heavy oil depending on the viscosity. Inexpensive C-heavy oil is mainly used as the primary fuel for power generation boilers.

   There is marine transportation by tanker and barge, land transportation pipeline and tank lorry as the receiving methods of this fuel oil. However, the land transportation by tank lorry is often unsuitable in terms of transportation capacity as the receiving method of main fuel. Fuel oil that received by marine transportation or land transportation is once stored in the storage tank after weighing by the flow meter and is discharged according to required amount of boiler. System schematic of receiving and storage of fuel oil is shown in Fig-2 and they are composed unloading arm (it is not required for land transportation), air separator, strainer, flow meter, storage tank, piping and valves which connecting each facilities as facility. Furthermore, the incident prevention facility such as oil dike, fire extinguishing facility, and oil separator is important facility provided with the receiving and storage facility, since fuel oil is a hazardous material.

2. Liquid fuels are refined petroleum products mainly from crude oil as raw material, which typical one is heavy oil. Crude oil contains a various kind of compounds such hydrocarbons, sulfur compounds, nitrogen compounds, oxygen compounds and with traces of muddy vanadium compounds metals such as vanadium and sodium even trace amount. The hydrocarbons which compose crude oil are classified into the paraffinic type ($C_nH_{2n}^{+2}$), olefinic type (unsaturated hydrocarbon chain C_nH_{2n}), naphthenic (cyclic hydrocarbon C_nH_{2n}) and aromatic type ($C_nH_{2n}^{-6}$). Recently, the use of residual oil and petroleum coke is increasing as the inexpensive fuel. Light oil is used as fuel for boiler startup or ignition.

   An example of the process of refining crude oil and various types of petroleum products is shown in Fig-1. The imported crude oil is sent to the atmospheric distillation equipment after dehydration and desalination by desalination equipment and is divided into light gasoline, heavy gasoline (naphtha), kerosene, light oil and residual oil. In addition, lubricant, coke, asphalt and paraffin are produced by vacuum distillation equipment under depressurization from residual oil. Quality and quantity of various products separated by atmospheric distillation equipment is governed by the properties of crude oil, gasoline is produced by increasing octane number by reforming the heavy gasoline equipment and decomposition by catalytic cracking unit in order to increase gasoline which has a lot of demand is produced.

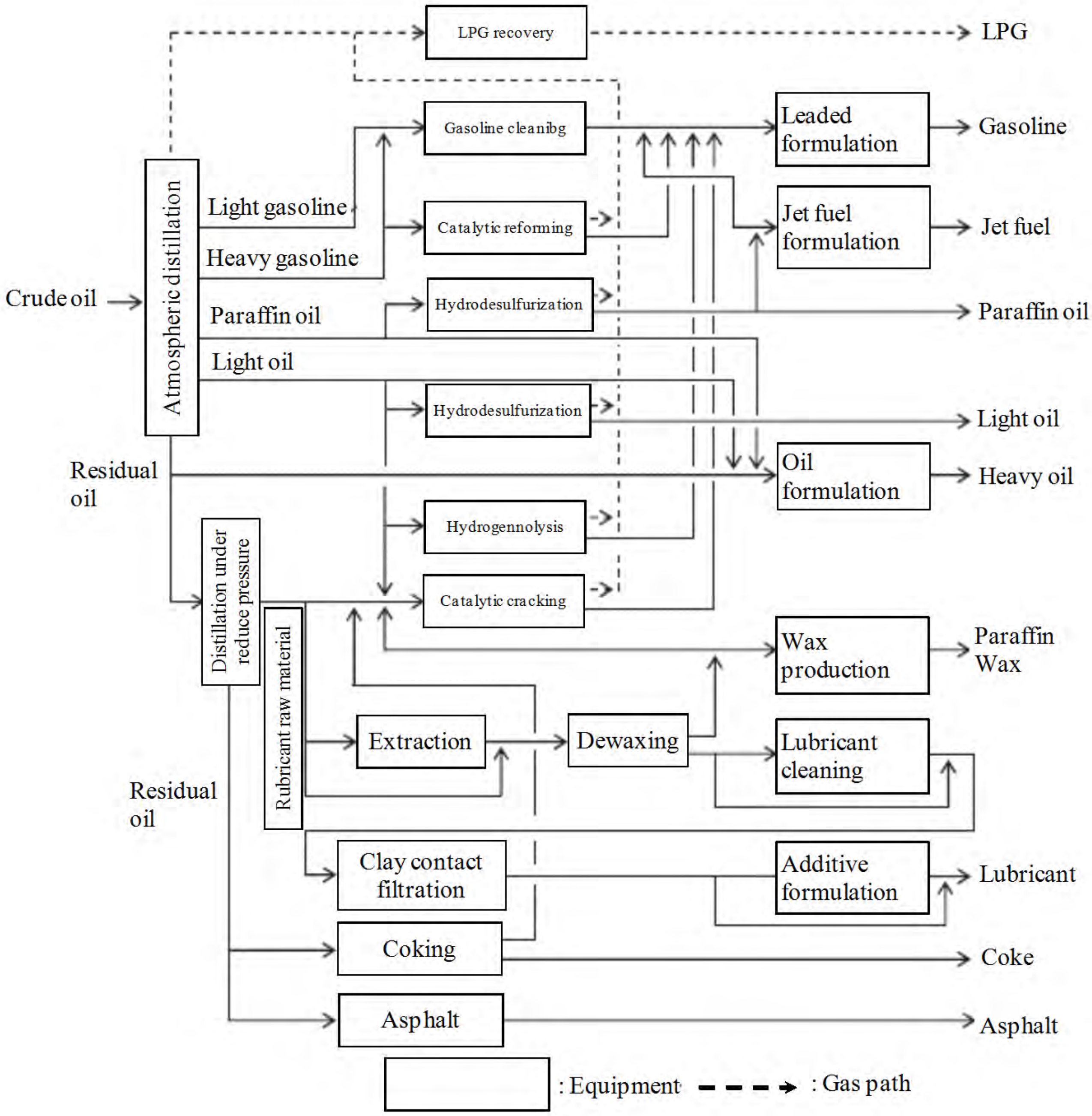


Fig- 1: Refining processes of petroleum products

Reference: P-43 of Journal (No.588: Sept. /2005): TENPES

(1) Heavy oil

Properties of heavy oil such as viscosity, pour point, and sulfur content are specified in JIS (Japanese Industrial Standard) as shown Table-2. Heavy oil has been divided into three types depending on the application type-1 to type-3, type -1 is called A-heavy oil, type-2 is called B-heavy oil, and type-3 is called C-heavy oil. A-heavy oil is produced by blending light oil with a small amount of residual oil from the atmospheric gas oil distillation equipment. B-heavy oil and C-heavy oil is produced by blending light oil with a small amount of residual oil from the atmospheric gas oil distillation or vacuum distillation and adjusting the viscosity.

Generally, C-heavy oil (JIS type-3 No. 2 or No.3) has been used as boiler fuel for power generation. It is used after heating by oil heater so that the viscosity become suitable for spray by burner, since kinematic viscosity (at 50^{o}C) is 50~1,000cSt and high. It is not necessary to heat B-heavy oil, since B has a lower viscosity than C. A-heavy oil can be used without heating equipment, since it has low pour point, low viscosity and good liquidity at room temperature.

Table- 2: Standard of heavy oil (JIS K2205-1991)

<table>
<tr><th colspan="2">Characterization / Type</th><th>Reaction</th><th>Flash point (°C)</th><th>Kinetic viscosity (50°C) cSt(mm²/s)</th><th>Pour point (°C)</th><th>Mass of carbon residue (%)</th><th>Mass of water (%)</th><th>Mass of ash (%)</th><th>Mass of sulfur content (%)</th></tr>
<tr><td rowspan="2">Type-1</td><td>No.1</td><td rowspan="6">Neutral</td><td rowspan="3">60≤</td><td rowspan="2">20≥</td><td rowspan="2">5≥ (1)</td><td rowspan="2">4≥</td><td rowspan="2">0.3≥</td><td rowspan="3">0.05≥</td><td>0.5≥</td></tr>
<tr><td>No.2</td><td>2.0≥</td></tr>
<tr><td colspan="2">Type-2</td><td>50≥</td><td>10≥ (1)</td><td>8≥</td><td>0.4≥</td><td>3.0≥</td></tr>
<tr><td rowspan="3">Type-3</td><td>No.1</td><td rowspan="3">70≤</td><td>250≥</td><td>—</td><td>—</td><td>0.5≥</td><td rowspan="2">0.1≥</td><td>3.5≥</td></tr>
<tr><td>No.2</td><td>400≥</td><td>—</td><td>—</td><td>0.6≥</td><td>—</td></tr>
<tr><td>No.3</td><td>1000≥, >400</td><td>—</td><td>—</td><td>2.0≥</td><td>—</td><td>—</td></tr>
</table>

Remarks-1: Type of heavy oil is classified as follows; type-1 (A-heavy oil) No.1 and No.2, type-2 (B-heavy oil), type-3 (C-heavy oil) No.1~No.3.

Remarks-2: Quality of heavy oil must comply with the provisions of the above.

Remarks-(1): Pour point for the cold weather of type-1 and type-2 must be less than 0^{o}C and pour point for the warm weather must be less than 0^{o}C.

Reference: P-44 of Journal (No.588: Sept. /2005): TENPES

(2) Crude oil

There is significant difference in physical properties such as specific gravity, flash point and viscosity change when comparing the properties of heavy oil and crude oil. The degree of difference is a slight difference in the origin of crude oil, crude oil has low specific gravity, flash point is low and viscosity is low compared with heavy oil, since crude oil contained oil-rich volatile light components (gasoline).

(3) Naphtha

Naphtha is the heavy gasoline obtained from crude oil distillation at atmospheric distillation equipment and is divided into light naphtha (range of boiling point is about 30~100^{o}C) and heavy naphtha (range of boiling point is about930~200^{o}C). Recently, high octane gasoline has been purified by reformer, although the heavy naphtha obtained by the distillation of crude oil was called direct distillated gasoline, since it has low octane for automotive gasoline engines. The direct distillated gasoline is called "Naphtha" in order to distinguish high octane gasoline.

(4) High pour point oil

High pour point crude oil is used for low sulfur fuel oil. High pour point crude oil is the Minas type heavy oil which contains a large amount of paraffin and which paraffin solidified and precipitated at room temperature. (melting temperature of paraffin is about 42^{o}C)

(5) Light oil

Property of light oil is stipulated in JIS as well as heavy oil as shown Table-3. Light oil is used as fuel for firing up when steam for heating of heavy oil is not obtained at the boiler startup, since heating is not required when combusting because light oil has low pour point. For the same reason, it also used as fuel for ignition. Calorific value of light oil is 44,000~46,000kJ/kg and higher than heavy oil. In addition, specific gravity is about 0.8~0.9 (at 15/4 ^{o}C) and less than heavy oil.

Table- 3: Standard of light oil (JIS K2204-1997)

Characterization / Type	Flash point (°C)	Distillation characteristics 90% distillation temp. (°C)	Pour point (°C)	Clogging point (°C)	Mass of remaining carbon element in 10% residue (%)	Cetan index (1)	Kinetic viscosity (30°C) cSt(mm^2/s)(2)	Mass of sulfur content (%)
Special No.1	≥50	360≥	5≥	—	0.1≥	≥50	≥2.7	0.05≥
No.1	≥50	360≥	-2.5≥	-1≥		≥50	≥2.7	
No.2	≥50	350≥	-7.5≥	-5≥		≥45	≥2.5	
No.3	≥45	330≥	-20≥	-12≥		≥45	≥2.0	
Special No.3	≥45	330≥	-30≥	-19≥		≥45	≥1.7	

Remarks-1: Light oil is classified into 5 types, special No.1, No.1, No.2, No.3, and special No.3 depending on the pour point.

Remarks-2: Quality of light oil must comply with the provisions of the above excluding water and sediment.

Remarks-(1): The cetan number can be used for cetan index.

Remarks-(2): 1mm^2/s=1cSt

Reference: P-44 of Journal (No.588: Sept. /2005): TENPES

(6) Kerosene

Property of kerosene is stipulated in JIS as shown Table-4. Kerosene is used as fuel for home heating and usually is also used as fuel for boiler power generation, since it has less environmental sulfur.
It is possible to burn kerosene at room temperature as well as light oil; however, it must be paid in

consideration of the material because of poor lubrication of oil pump. Calorific value and specific gravity is comparable to light oil.

Table- 4: Standard of paraffin oil (JIS K2203-1996)

Characterization / Type	Reaction	Flash point (ºC)	Distillate temp. of 90% distillation characteristics (ºC)	Sulfur content (%)	Smoke point	Copper corrosion (50 ºC3h)	Color (Saybolt)
No.1	Neutral	≥40	270≥	0.008≥	≥23(1)	1≥	≥25
No.2			300≥	0.50≥	—	—	—

Remarks-1: Kerosene is classified into two types, No.1 is for lighting, heating, kitchen and No.2 is for engine fuel and cleaning solvents.

Remarks-2: Quality of kerosene must comply with the provisions of the above excluding water and sediment.

Remarks-(1): Smoke point of No1. For the cold weather must be more than 21mm.

Reference: P-44 of Journal (No.588: Sept. /2005): TENPES

(7) Natural gas liquid (NGL)

NGL (Natural Gas Liquid) is also called CHPS (Casing Head Petroleum Spirit) and is the natural gasoline which is taken as a byproduct of natural gas field when natural gas mining. Heavy gas of the higher hydrocarbons such as Propane (C_3H_8), Butane (C_4H_{10}), Pentane (C_5H_{12}) other than Methane (CH_4) are included in the natural gas that is collected from gas field and NGL is separated and purified in the course of these.

(8) Methanol

Methanol is a colorless, soluble in alcohol, ether and water, flammable liquid that is volatile. In general, it is synthesized by catalytic reaction of synthesis raw gas under high pressure, which is the gas mixture obtained by catalytic steam reforming of hydrocarbons (CO) and hydrogen (H_2) gas.

$$CO + 2H_2 \rightarrow CH_3OH$$

Therefore, the sulfur content is not contained in the synthesized methanol at all.

3. Categorization of fluids

The fluids to be transported must be placed in one of the following five categories in the Table-5 according to the hazard potential in respect of public safety:

Gases or liquids not specifically included by name must be classified in the category containing fluids most closely similar in hazard potential to those quoted. If the category is not clear, the more hazardous category must be assumed.

Table- 5: Categorization of fluids

Category A	Typically non-flammable water-based fluids.
Category B	Flammable and/or toxic fluids which are liquids at ambient temperature and at atmospheric pressure conditions. Typical examples are oil and petroleum products. Methanol is an example of a flammable and toxic fluid.
Category C	Non-flammable fluids which are non-toxic gases at ambient temperature and atmospheric pressure conditions. Typical examples are nitrogen, carbon dioxide, argon and air.
Category D	Non-toxic, single-phase natural gas.
Category E	Flammable and/or toxic fluids which are gases at ambient temperature and atmospheric pressure conditions and are conveyed as gases and/or liquids. Typical examples are hydrogen, natural gas (not otherwise covered in category D), ethane, ethylene, liquefied petroleum gas (such as propane and butane), natural gas liquids, ammonia and chlorine.

Reference: 5.2 of ISO 13623-2000

Article 60. Oil unloading facility

Article 60-1. Mooring Equipment

1. There are methods for receiving marine transported oil such as "dolphin type" which extends quay to the sea as shown in Photo-2 and 4, "sea berth type" which lays piping on the seabed as shown in Photo-1 and unload at the sea and "berthing method" which comes directly alongside to quay and the like as shown in Photo-3. In either method, the unloading arm which consist of metal universal joint and piping is used so that the connecting part discharge of unloading pump on the ship with the receiving pipe on land follow the change of ship due to rocking draft and by tides or waves.
2. A proper fender must be provided on the quay in order to perform safe unloading work by fixing tanker.

Photo- 1: Sea berth type

http://hawaiihouseblog.blogspot.com/2009_12_01_archive.html

Photo- 2: Dolphin type

http://commons.wikimedia.org/wiki/File:Oil_jetty_-_geograph.org.uk_-_216147.jpg

Photo- 3: Direct berthing type

http://www.guardian.co.uk/world/2010/may/06/sailors-russian-tanker-hijacked-somali-pirates

Photo- 4: Dolphin type

http://shipphoto.exblog.jp/m2005-05-01/

Article 60-2. Un-loading facility

1. Typical concept of fuel oil handling facilities for oil thermal power plant is summarized in Fig-5.
2. General flow from tanker to the storage tank is shown in Fig-6 and from receiving to power plant is shown in Fig-2. in considering the transportation method.
3. The “pipeline facility” means the pipeline with compressor or pump stations, pressure control stations, flow control stations, metering, tankage, supervisory control and data acquisition system (SCADA), safety systems, corrosion protection systems, and any other equipment, facility or building used in the transportation of fluids.
4. The “offshore raiser” means that part of an offshore pipeline, including subsea spool pieces, which extends from the sea bed to the pipeline termination point on an offshore installation. The offshore risers should be given careful design consideration because of their criticality to an offshore installation and its exposure to environmental loads and mechanical service connections. The following factors should be taken into consideration in their design:

1) splash zone (loads and corrosion);
2) reduced inspection capability during operation;
3) induced movements;
4) velocity amplification due to riser spacing;
5) possibility of platform settlement;
6) protection of risers by locating them within the supporting structure.

5. Unloading arm and pipe on the ship has often been joined by flange joint in order to save labor and to consider emergency withdrawal in an emergency, which the cam lock flange quick coupler is also often used as shown in Fig-3, 4 and Photo-9 and 10, since it takes a lot of time to disconnect in order to tighten the flange bolts. The unloading arm is typically used at a rate faster than the velocity in the pipe, it is expensive compared with the pipe and the pressure loss is not so problem because of shorter distances. But the flow rate is commonly used around 5m/sec~10m/sec, since extreme high speed may cause vibration. However, it is preferable to control flow rate low in terms of generation of static electricity. Typical unloading arm is shown in Photo-5, 6, 7 and the marine hose is shown in Photo-1, 8, 17, 18.

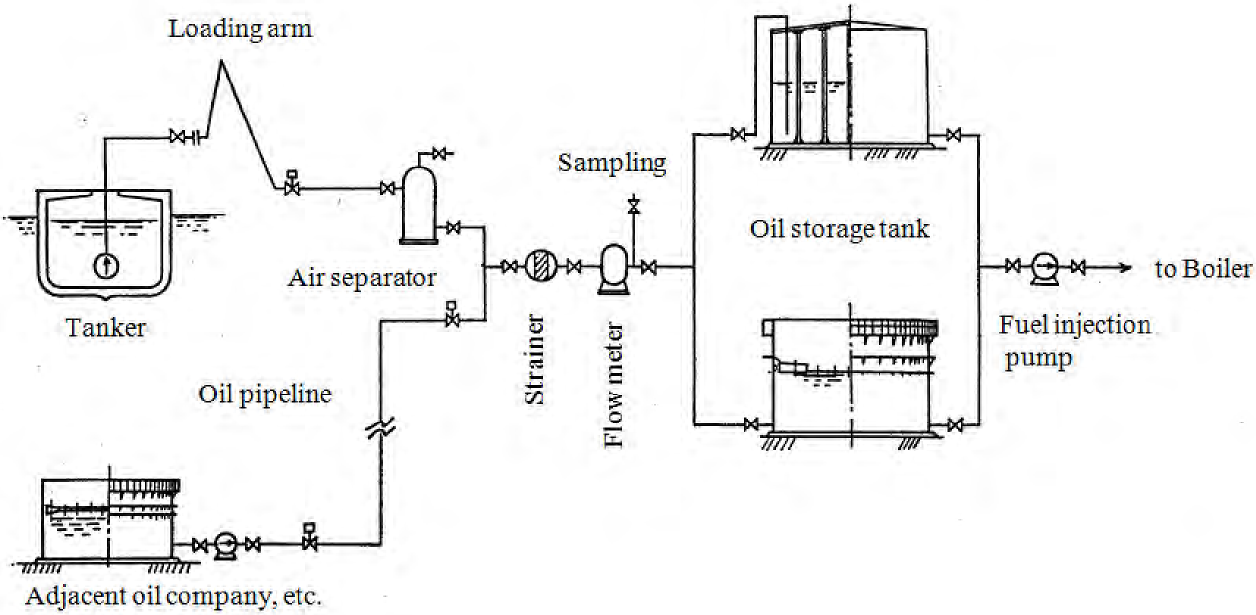


Fig- 2: Typical system of oil unloading facility

Reference: P-119 of Journal (No.516: Sept. /1999): TENPES

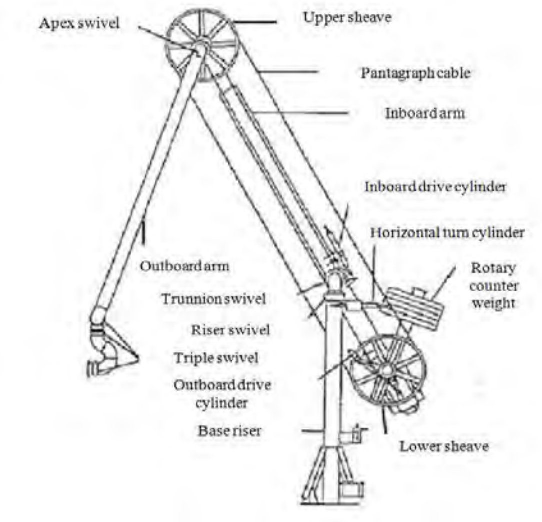


Fig- 3: Construction of loading arm

Reference: P-119 of Journal (No.516: Sept. /1999): TENPES

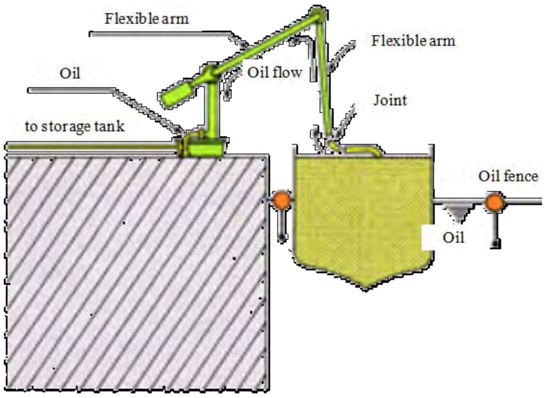


Fig- 4: Typical function of loading arm

http://www.energia.co.jp/energy/eco/envir2000/environ3d.html

Photo- 5: Oil unloading facility

http://www.seanews.com.tr/article/TURSHIP/TANKERS/69630/Oil-Fleet/

Photo- 6: Oil unloading from super tanker

http://www.ndl.ns.ca/photos.html

Photo- 7: Oil unloading facility

http://www.niigata-ls.co.jp/jp/topics/2011/201110_kashima.html

Photo- 8: Marine hose

http://www.suzuei.co.jp/business/marine/item01/

Photo- 9: Oil unloading coupler

http://www.repsol.com/es_en/productos_y_servicios/servicios/terminales_maritimas/marine_terminal_3/graphics__photos/default.aspx Article 60-3. Fence

Photo- 10: Oil unloading coupler

http://oilrotterdam.vopak.com/news/137_136.php

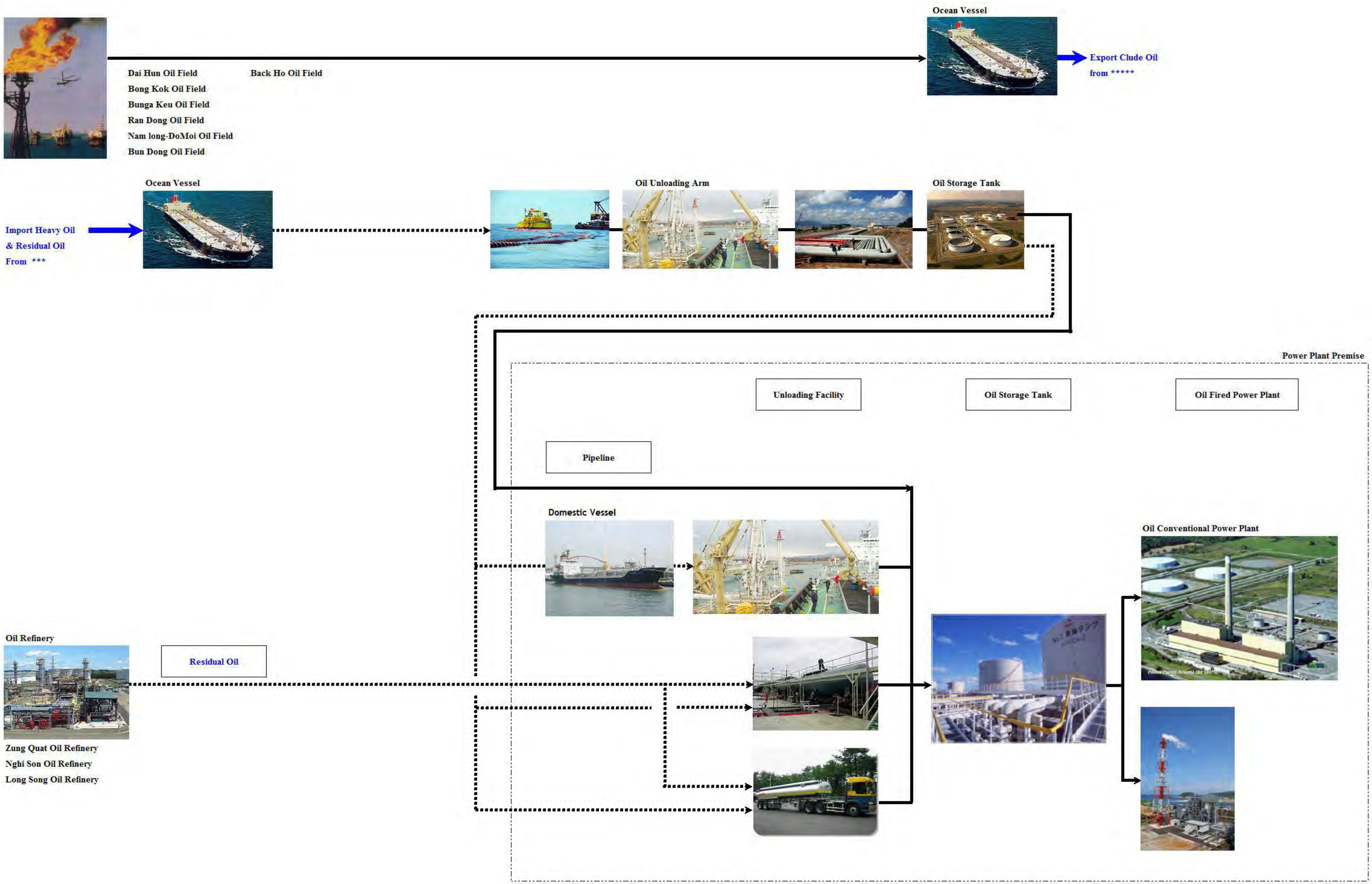


Fig- 5: Construction concept of fuel handling facilities for oil thermal power plant

Article 60-3. Fence

1. Oil unloading berth must be off limits other than those permitted in order to ensure safety as shown in Photo-11, 12, 13, 14, since flammable dangerous materials is handled. Also, the bonded area and restricted area must be clarified by a fence to block, since it is necessary to storage for customs in the port of importation.

Photo- 11: Tanker wharf keep out fence

http://www.photoready.co.uk/scenes/oil-tanker-unloading.html

Photo- 12: Fence for port bonded area

http://www.geolocation.ws/v/W/4d67608e8786560f3d02216d/bonded-installation-warning-at-south/en

Photo- 13: Tanker wharf keep out warning

http://vilagvasutai.hu/zutazasok/ausuz2010/auuz10orszageng.html

Photo- 14: Tanker wharf keep out warning

http://blogs.yahoo.co.jp/gtcct036/folder/865061.html?m=lc&p=11

Article 60-4. Purge equipment

1. The marine hose (oil handling hose) as shown in Fig-6 and Photo-1, 8, 17, 18 is used between tankers and onshore storage facilities. “Sink float method”, “Permanent floating method”, “Submarine method”, “Double carcass with oil leak detection system” and the like are applied to the marine hose.

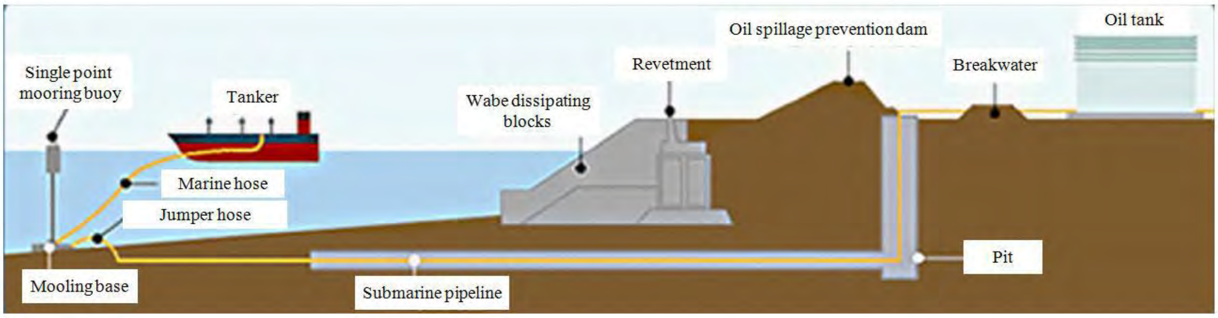


Fig- 6: Single point mooring buoy

http://www.fosco.jp/takuwae.html

2. Inert gas system

In order to prevent the ignition of oil cargo, inert gas is sent to oil tank by inert gas system, which removes the soot, sulfur emissions and moisture and send it to oil storage tank. Combustion or explosion cannot occur due to the absence of oxygen, even if fire goes into the petroleum or crude oil tank filled with this inert gas instead of combustible gas or air. The equipment for inert gas system is shown in Photo-15, 16.

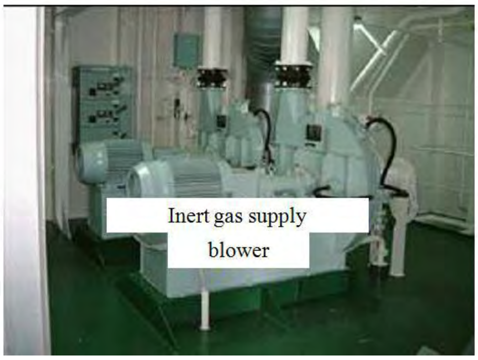


Photo- 15: Inert gas supply blower

http://www.nexyzbb.ne.jp/~j_sunami76/shoubou_se.html

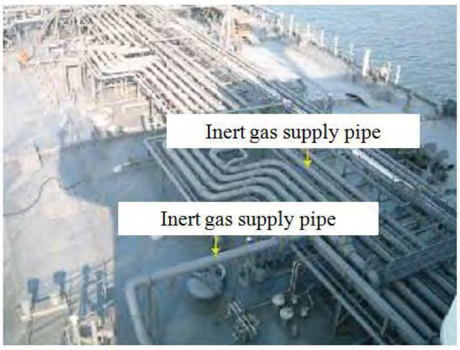


Photo- 16: Inert gas supply piping

http://www.nexyzbb.ne.jp/~j_sunami76/shoubou_se.html

Photo- 17: Marine hose for unloading

http://www.kline.co.jp/csr/safety/management.html

Photo- 18: Marine hose for unloading

http://www.tradewindsnews.com/tankers/article643585.ece

Article 60-5. Sign

1. When transporting and unloading volatile oils, it is necessary to pay attention to explosion and fire. As international flag of ship “B-flag: I am taking in, discharging or carrying dangerous cargo.” As shown in Photo-20 as well as established “Off limits other than those involved” must be displayed with “Loading of dangerous goods” as shown in Photo-19 or “Under handling of cargo”.

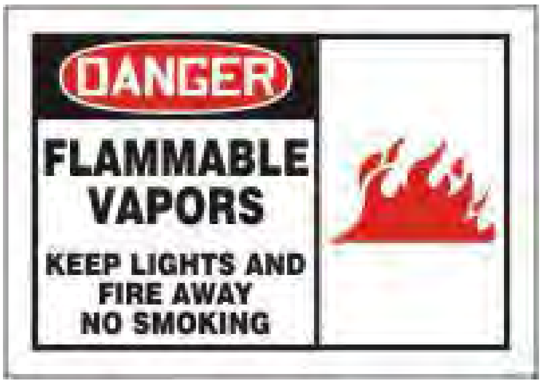


Photo- 19: Warning board

http://www.firstaidandsafetyonline.com/showproduct~catid~350.asp

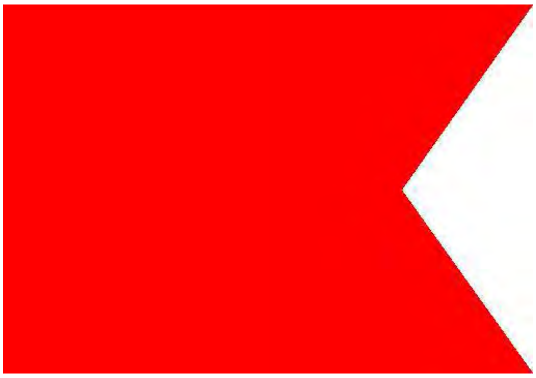


Photo- 20: International B-flag

http://sekikaiji.co.jp/practice/41/sinngouki.html

Article 61. Oil metering facility

Article 61-1. Location of metering facility

1. Metering equipment is consists of an air separator, strainer, flow meter, sampling equipment and the like.

(1) Air separator

A lot of air mix into the oil just before the start and completion of receiving, since the unloading arms for receiving oil from ocean carrier is held in the empty state except when unloading oil. The air separator is provided to eliminate air and perform accurate weighing. The air separator for land transportation metering equipment is often omitted. Installation of the vent tank or built-in of back-up system is also necessary, since vent of vapor mist from exhaust of separator and oil leak in the case of trouble is supposed. The principle and structure of the air separator is shown Fig-7.

(2) Strainer

Strainer is intended to prevent the intrusion of things inside the flow meter, filter with about 25~40mesh, filtration area with about four times those of the cross section of pipe is often used. The automatic washing strainer is used in order to increase acceptance capacity of flow meter, labor saving of net cleaning, ensuring of safety. Fig-8 and Photo-21 show the construction of automatic washing strainer and line strainer.

(3) Flow meter

It is preferable that the difference between those instruments is to be small as much as possible, since measuring by flow meter is underlying transactions. Today, the positive displacement flow meter which is accurate and easy to handle even the instrumental error of less than ±0.2% between 0.3cP~150cP without adjustment is made and widely used, since it is necessary to measure from low viscosity ranging such as crude oil or naphtha to high viscosity such as heavy oil by a flow meter with the diversification of the fuel oil. There are limits for unit capacity of the flow meter to use accurately, 1,000kg/h in gear type meter and about 3,000kg/h in spiral type meter, it is necessary to place addition if it is required more weighing. Fig-9 shows the structure of gear type displacement flow meter.

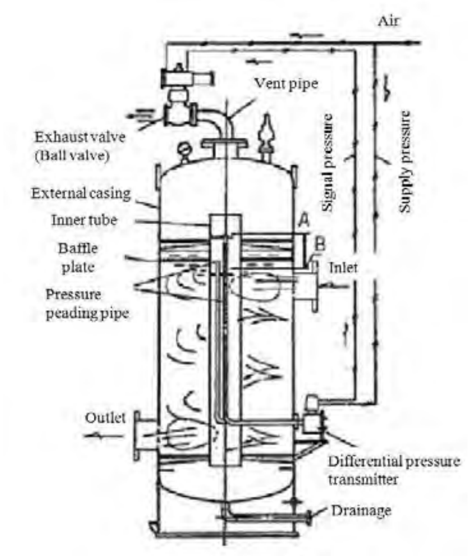


Fig- 7: Air separator

Reference: P-121 of Journal (No.516: Sept. /1999): TENPES

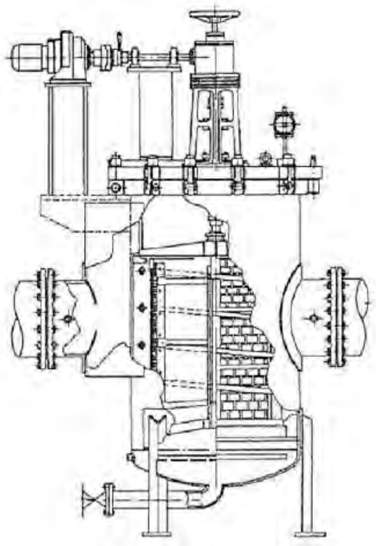


Fig- 8: Automatic washing strainer

Reference: P-122 of Journal (No.516: Sept. /1999): TENPES

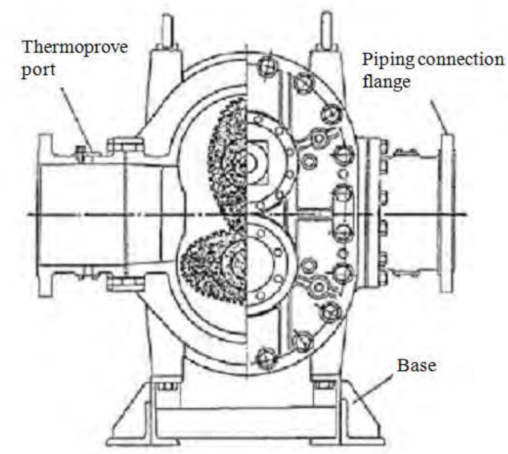


Fig- 9: Gear type positive displacement flowmeter

Reference: P-122 of Journal (No.516: Sept. /1999): TENPES

Photo- 21: Line strainer

http://www.jamisonproducts.com/strainers/basket-strainers/oil-basket-strainer.html

2. Generally, the metering equipment is often used those which necessary equipments are integrated on the skid as shown in Photo-22, 23, 25.
3. If a storage tank is installed in the power plant premise, transportation distance to the boiler can be reduced the transportation distance, if power plant is far from the unloading port; oil is transported long-distance by the dedicated pump station as shown in Photo-24.

Photo- 22: Ultrasonic fiscal meterinf skid

http://www.fbgroup.com/Referenties.aspx?Pagina=8&Referentie=7

Photo- 23: Metering system

http://www.sasinternasional.com/product-services/metering-system/

Photo- 24: Pumping station

http://phx.corporate-ir.net/External.File?item=UGFyZW50SUQ9NDAyNjkyNnxDaGlsZElEPTQyNTgzOHxUeXBlPTI=&t=1

Photo- 25: Crude oil receiving metering facility

http://www.midtap.com.eg/english/gallery.html

Article 61-2. Testing procedure of metering facility

1. Measuring instruments can be tested and calibrated regularly.

Article 61-3. Sampling

1. It is necessary to know exactly what their properties when receiving fuel oil. Therefore, autosampler is installed in immediately after the flowmeter in order to take sample representing the whole

securely as shown in Fig-10 and Photo-26.

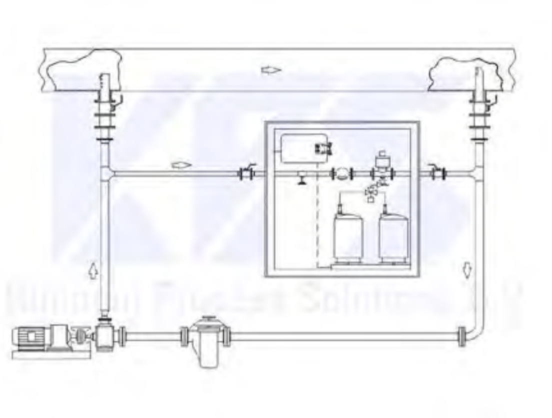


Fig- 10: Crude oil sampler

http://www.kpsnl.com/en/products-services-en/automatic-samplingblending-en/crude-sampling-en

Photo- 26: Crude oil sampler

http://www.eesiflo.com/watercut_monitoring_mbw.html

Article 61-4. Future installation

1. When providing the metering equipment, the extra-line, the maintenance space, the future space must be secured in order to repair strainer or gear pump and for the calibration of measuring instruments.

Article 62. Oil pipeline

Article 62-1. Monitoring equipment

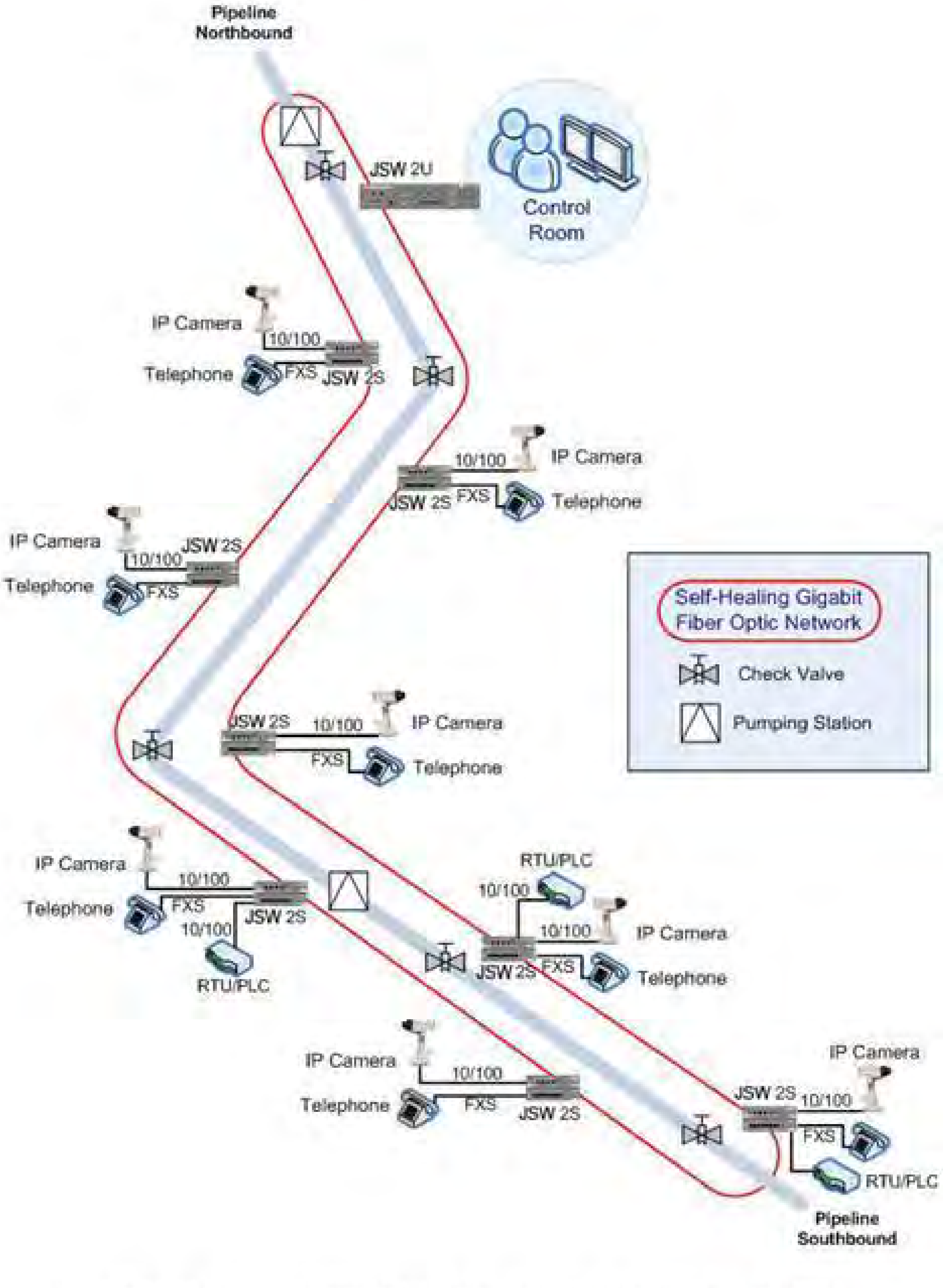
1. The real-time monitoring and control of facilities must be performed in the respective central monitoring control room as shown in Photo-27, 28 corresponding to the division to secure the safety and security, although the division of ownership of the oil receiving facility, oil discharge facility, oil transportation facility and the like has become different in individual cases.
2. Now, the pipeline is monitored remotely by the IP cameras, telephones and RTU/PLCs connected to the fiber optic network which is installed along the pipeline as shown in Fig-11, 12.

Photo- 27: Control room for oil pipeline

http://chosatai.potika.net/k/index.html?&m=d&id=36&p=2&AC=

Photo- 28: Control room for oil pipeline

http://www.stockphotopro.com/photo_of/BC/A750JG/Gas_and_Oil_Pipeline



Typical Pipeline Monitoring & SCADA application utilizing 2U and 2S JumboSwitches.

Fig- 11: Typical pipeline monitoring and SCADA application

http://www.novaca.com/Ethernet/384x%20Series/tc3840.htm

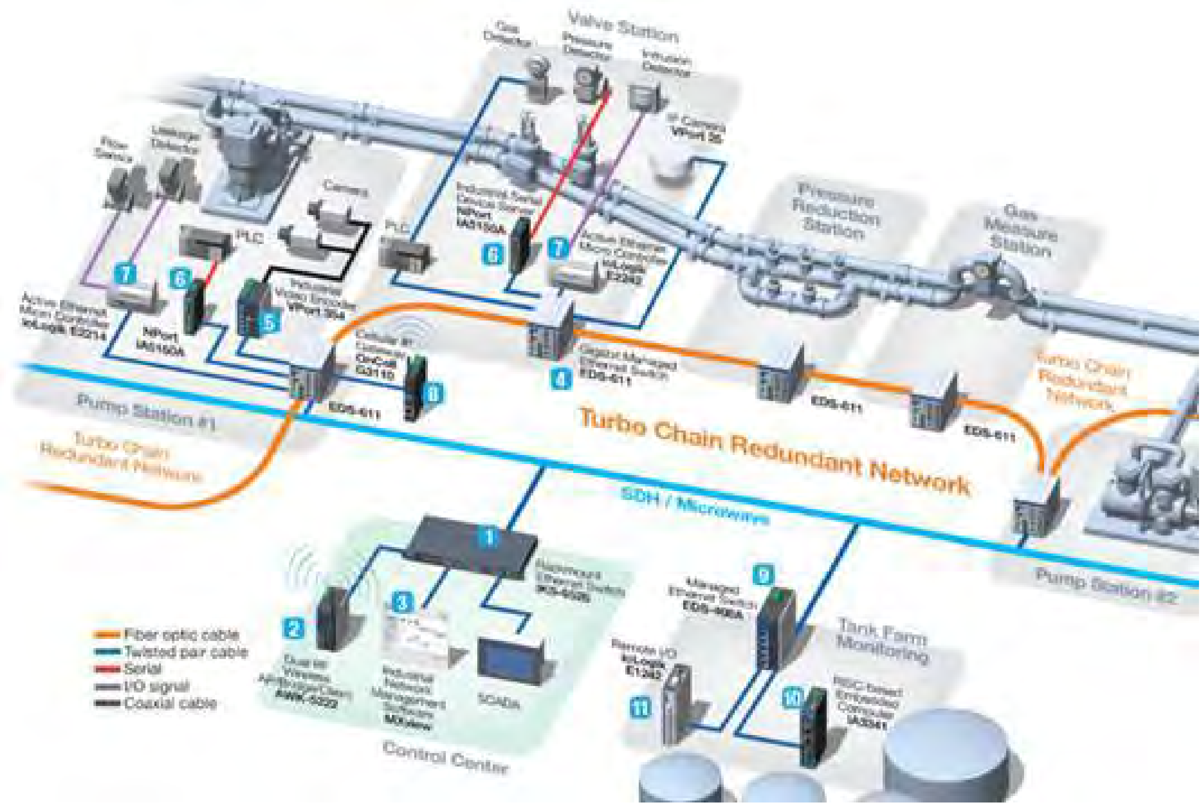


Fig- 12: Real-time monitoring of oil pipeline systems

http://www.moxa.com/Event/Net/2010/Oil_and_gas_2010/solution_pipeline.htm

Article 62-2. Shut-off valve

1. A valve must be installed at each of the following locations according to ASME B16.8-846 and 49 CFR 195-260:

   1) On the suction end and the discharge end of a pump station in a manner that permits isolation of the pump station equipment in the event of an emergency.

   2) On each line entering or leaving a breakout storage tank area in a manner that permits isolation of the tank area from other facilities.

   3) On each mainline at locations along the pipeline system that will minimize damage or pollution from accidental hazardous liquid discharge, as appropriate for the terrain in open country, for offshore areas, or for populated areas.

   4) On each lateral takeoff from a trunk line in a manner that permits shutting off the lateral without interrupting the flow in the trunk line.

5) On each side of water crossing that is more than 100 feet (30 meters) wide from high-water mark to high-water mark unless the Administrator finds in a particular case that valves are not justified.

6) On each side of a reservoir holding water for human consumption.

2. Section isolation valves

Section isolation valves must be installed at the beginning and end of a pipeline and where required for:

1) operation and maintenance;
2) control of emergencies;
3) limiting potential spill volumes.

Account should be taken of topography, ease of access for operation and maintenance including requirements for pressure relief, security and proximity to occupied buildings when locating the valves. The mode of operation of section isolation valves must be established when determining their location.

3. Photo-29, 30, 31, 32, 33 shows typical valves and actuator. Ball, check, gate and plug valves must meet the requirement of ISO 14313. Valves for subsea application must meet the requirement of ISO-14723.

Photo- 29: Shut-off valve between marine hose and subsea pipeline

http://www.suzuei.co.jp/business/marine/item01/

Photo- 30: Shut-off valve between marine hose and subsea pipeline

http://www.suzuei.co.jp/business/marine/item01/

Photo- 31: Globe valve for pipeline

http://www.hiwtc.com/products/oil-and-gas-transport-pipeline-globe-valves-3089-26366.htm

Photo- 32: Ball valve for pipeline

http://www.seekpart.com/valves-fittings/valves/oil%20pipeline%20valve.html

Photo- 33: Subsea actuator

http://pegaltd.com/3.pdf

Schuck type Borsig supertorc® actuators are also suitable for underwater operation. They are designed so that they can also be mounted on the ball valve under water. For this application the actuator is sealed from the outside and completely filled with biologically degradable oil. A pressure equalizing arrangement is provided to balance the internal pressure of the actuator to the external water pressure. The actuator is used at any depth. An external mechanical position indicator is present, all parts in contact with water being made of stainless steel. Any possible leak at the stem seal of the valve is discharged via a pressure release valve. In addition, the actuator can be equipped with limit switches and like all other type Borsig supertorc ® actuators, the sub-sea actuator is maintenance-free.

Article 62-3. Indication of valve opening status

1. Valve must have the indicator to be confirmed the opening easily as shown in Photo-34, 35. The opening of valve for remote operation must be indicated the degree of opening in a central monitoring room.

Photo- 34: Degital indicator for crude oil valve

http://www.flowserve.com/Products/Automation/Actuators-Electric/MX-Electronic-Valve-Actuator,en_US

Photo- 35: Analog indicator

http://www.valmatic.com/actuation_travelingnut.html

Article 62-4. Leakage detector for oil receiving pipeline

1. The oil leakage detector for the pipeline is applied following three basic methods

(1) Device which is capable to automatically detect the leakage of oil by measuring oil flow in the pipeline as shown in Fig-14.

(2) Device which is capable to automatically detect the leakage of oil by measuring oil pressure in the pipeline.

(3) Device which is capable to detect the leakage of oil by measuring oil pressure restrained to a certain pressure in the pipeline as shown in Fig-13.

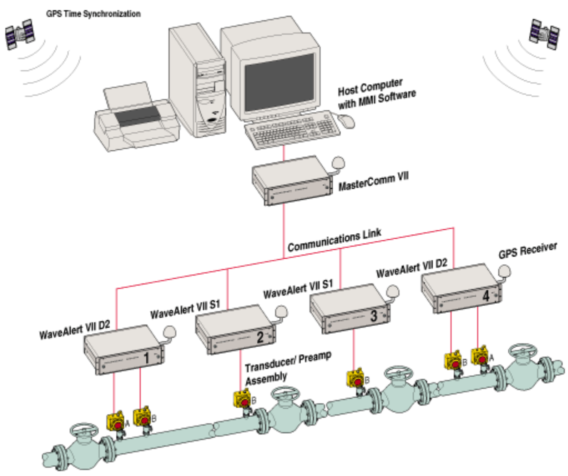


Fig- 13: Oil leak detection system

http://www.ec-africa.com/scada.htm

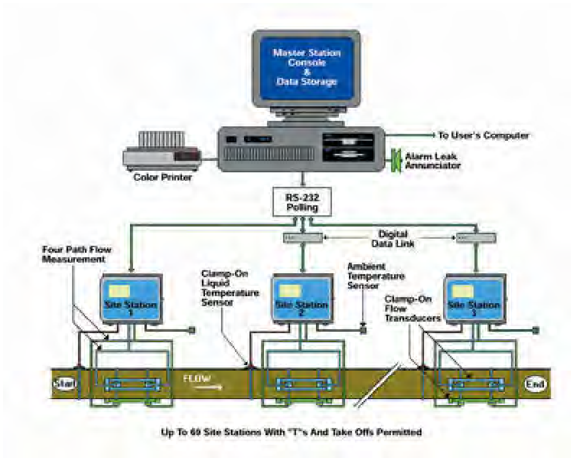


Fig- 14: Oil leak detection system

http://www.flowcontrolnetwork.com/containment/pipe/article/oil-pipeline-leak-detection-and-location

Article 62-5. Location of leakage detector

1. Central to the CONTROS monitoring concept for subsea oil and gas production is the HydroC™ CH_4 as shown in Photo-37, which was specifically developed to allow fast, real-time and in-situ detection

of gaseous and even dissolved hydrocarbons/methane in the water column. The HydroC™ CH_4 has been successfully implemented in leak detection surveys and pipeline inspections to water depths up to 10,000 Ft. and responds to all hydrocarbons including natural gas and crude oil. In order to achieve the best and individualized monitoring solutions, CONTROS offers consulting and engineering services.

Photo- 36: Pressure sensor

http://www.flowmeterdirectory.com/european-compliant-watercut-meters.html

Photo- 37: Hydrocarbon & methane sensor

http://www.contros.eu/products-hydroC-CH4-OG.html

Article 62-6. Seismic sensor

1. If an earthquake occurs, it is necessary to stop the transportation and to restart after safety checks in order to prevent secondary disasters such as long-term oil spills from the breaking point. Therefore, it is necessary to install the seismoscope senses automatic shutoff device and the remote shutoff device which is capable to stop oil transportation from central control and command room. In addition, the establishment of the sub-center must be considered, if the central and command room were affected. The seismic sensor and seismic sensing system are shown in Fig-15 and Photo-38.

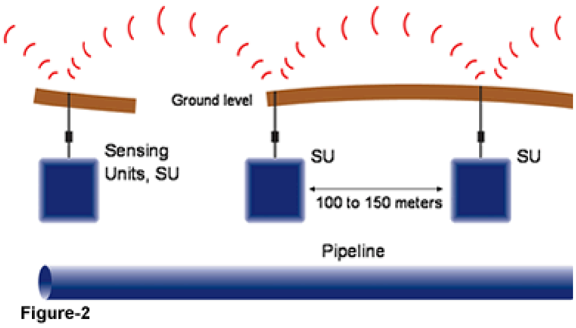


Fig- 15: Seismic sensing system

http://www.depcosystems.com/Services/Security2.html

Photo- 38: Seismic sensor

http://www.ubukata.co.jp/product/product02.html

Article 62-7. Warning equipment

(1) The operation end of public-address system must be provided on the pier, in the monitoring room and the like.
(2) The speaker for public-address system must be provided in a location where it can be heard such as the quay or the premises.
(3) The emergency bell can be stop when using the public-address system.
(4) The receiving part of alarm equipment must be provided in the monitoring room and the like.
(5) The alarm bell and red indicator must be provided in the receiving point of alarm equipment.
(6) The heat resistant wiring and the like must be used for electrical wiring.
(7) The emergency bell may not provide if the speaker will emits siren by actuating the transmitter.
(8) Some of the alarm equipment can be substituted by phone if installing the emergency call.

Article 62-8. Reporting equipment

(1) The transmitter must be provided by less than 2km along with the pipeline route.
(2) The receiving unit must be provided in the central control room and the like.
(3) The transmitter part must be provided in the place where alarm, red indicator and transmitter can be seen easily and operated easily.
(4) The receiver can be displayed and received alarm for each block, and must have a redundant power supply.

Article 62-9. Location of reporting equipment

(1) The reporting equipment to the fire authority must be provided in the receiving part of emergency reporting equipment in the central monitoring room.
(2) The dedicated telephone is considered as reporting equipment if the dedicated telephone which is capable to report the fire authority is installed in the receiving point of central monitoring room.

Article 62-10. Reporting facility

1. The operation status of fields and emergency matters such as fire must be aggregated and displayed in central monitoring room. The reporting system for the matters which is required to report to fire authority and the Coast Guard such as the oil leakage in the sea, fire, explosion, human accident must be installed in the central monitoring room among them as shown in Photo-39, 40.

Photo- 39: Fire reporting system

http://nishikoumuten.blogspot.com/2011/02/blog-post_3955.html

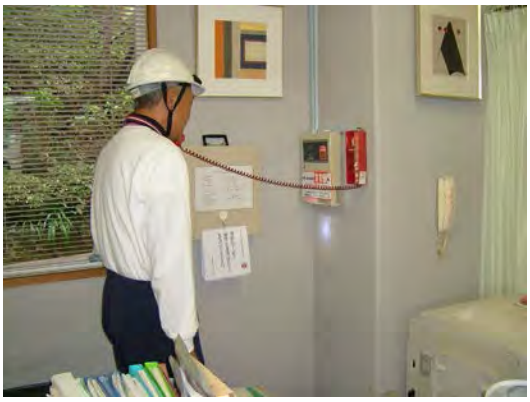


Photo- 40: Reporting to fire authority

http://www.town.kamitonda.lg.jp/shobo/syoubougyouzi/rinnku/H21.akinokasaiyobouunndou/sinnwaho-mu.htm

Article 63. Oil pumping facility

Article 63-1. Pumping unit

1. Oil unloading is performed by pump in the taker, though oil loading to tanker is performed by pump on the land. The tanker has been built to be loaded oil separately so as not to mix and has a main pipeline which is capable to transport great amount of oil and a strip line which is capable to handle the remaining oil. The pump for unloading oil through a main pipeline is driven by the steam turbine and number of units has been provided for large scale tanker as shown in Fig-16 and Photo-41.
2. The necessity of long-distance transportation or the classification of equipments to be owned is determined depending to the distance from storage tank to power plant or the presence of storage tanks in the power plant.

Photo- 41: Crago pump of VLCC

http://en.wikipedia.org/wiki/Oil_tanker

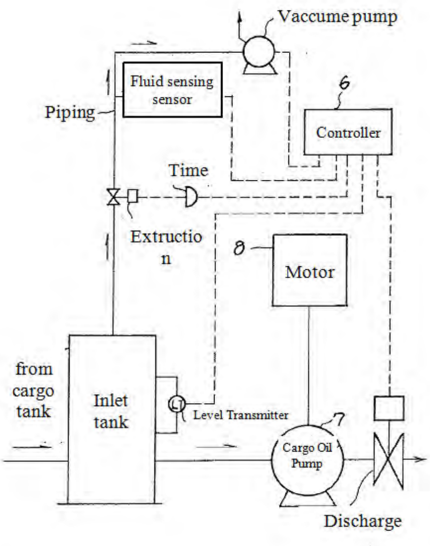


Fig- 16: Cargo pump

http://www.rdnavi.co.jp/utilitymodel/html/134605.html?word=&p=1&q=50&date=

Article 63-2. Other pumps

1. The necessity of long-distance transportation, specification of facilities and division of ownership are decided depending on the distance from the storage tank to power plant or the presence of storage tanks in the power plant, though the pump will be provided on the storage tank side when crude oil, heavy oil and the like is purchased from other oil company, or residual oil is purchased from the adjacent petroleum refinery company.

Article 64 General provision

Article 64-1. General provision for oil transportation facility

1. The concept of oil transportation is shown in Fig-5. However, this guideline details the only the transportation facilities by ship and pipeline and the transportation by vehicle and train is omitted.

Article 65. Material of oil pipeline

Article 65-1. Material for oil pipeline

1. As the material for the main pipeline, API (5L) standard X-42, X-52, X-60, X-65 steel pipe that has been used widely in the worldwide, which is excellent in flexibility and greater growth, which has tensile strength and toughness. In addition, the painting or coating such as polyethylene, coal-tar, enamel is applied to the outer surface of the pipe is covered to prevent corrosion.

Article 66. Structure of oil pipeline, etc.

Article 66-1. Structure of oil pipeline

1. Design principles

   The extent and detail of the design of a pipeline system must be sufficient to demonstrate that the integrity and serviceability required by this International Standard can be maintained during the design life of the pipeline system.

   Representative values for loads and load resistance must be selected in accordance with good engineering practice. Methods of analysis may be based on analytical, numerical or empirical models, or a combination of these methods.

   Principles of reliability-based limit state design methods may be applied, provided that all relevant ultimate and serviceability limit states are considered. All relevant sources of uncertainty in loads and load resistance must be considered and sufficient statistical data must be available for adequate characterization of these uncertainties.

   Reliability-based limit state design methods must not be used to replace the requirement in 10.2 for the maximum permissible hoop stress due to fluid pressure.

   NOTE: Ultimate limit states are normally associated with loss of structural integrity, e.g. rupture, fracture, fatigue or collapse, whereas exceeding serviceability limit states prevents the pipeline from operating as intended.

2. Route selection

Route selection must take into account the design, construction, operation, maintenance and abandonment of the pipeline in accordance with this International Standard. To minimize the possibility of future corrective work and limitations, anticipated urban and industry developments must be considered. Factors which shall be considered during route selection include:

1) safety of the public, and personnel working on or near the pipeline;
2) protection of the environment;
3) other property and facilities;
4) third-party activities;
5) geotechnical, corrosivity and hydrographical conditions;
6) requirements for construction, operation and maintenance;
7) national and/or local requirements;
8) future exploration.

3. Public safety

Pipelines conveying category B, C, D and E fluids must, where practicable, avoid built-up areas or areas with frequent human activity. In the absence of public safety requirements in a country, a safety evaluation must be performed in accordance with the general requirements of Annex A for:

1) pipelines conveying category D fluids in locations where multi-storey buildings are prevalent, where traffic is heavy or dense, and where there may be numerous other utilities underground;
2) pipelines conveying category E fluids.

4. Environment

An assessment of environmental impact must consider as a minimum:

1) temporary works during construction, repair and modification;
2) the long-term presence of the pipeline;
3) potential loss of fluids.

5. Other facilities

Facilities along the pipeline route which may affect the pipeline must be identified and their impact evaluated in consultation with the operator of these facilities.

6. Surveys

6.1 Pipelines on land

Route and soil surveys must be carried out to identify and locate with sufficient accuracy the relevant geographical, geological, geotechnical, corrosivity, topographical and environmental features, and other facilities such as other pipelines, cables and obstructions, which could impact the pipeline route selection.

6.2 Offshore pipelines

Route and soil surveys must be carried out on the proposed route to identify and locate:

1) geological features and natural hazards;
2) pipelines, cables and wellheads;
3) obstructions such as wrecks, mines and debris;
4) geotechnical properties.

Meteorological and oceanographical data required for the design and construction planning must be collected. Such data may include:

1) bathymetry;
2) winds;
3) tides;
4) waves;
5) currents;
6) atmospheric conditions;
7) hydrologic conditions (temperature, oxygen content, pH value, resistivity, biological activity, salinity);
8) marine growth;
9) soil accretion and erosion.

7. Loads

7.1 General

Loads, which may cause or contribute to pipeline failure or loss of serviceability of the pipeline system, must be identified and accounted for in the design. For the strength design, loads must be classified as:

1) functional; or
2) environmental; or
3) construction; or
4) accidental.

7.2 Functional loads

(1) Classification

Loads arising from the intended use of the pipeline system and residual loads from other sources must be classified as functional.

NOTE: The weight of the pipeline, including components and fluid, and loads due to pressure and temperature are examples of functional loads arising from the intended use of the system. Pre-stressing, residual stresses from installation, soil cover, external hydrostatic pressure, marine growth, subsidence and differential settlement, frost heave and thaw settlement, and sustained loads from icing are examples of functional loads from other sources. Reaction forces at supports from functional loads and loads due to sustained displacements, rotations of supports or impact by changes in flow direction are also functional.

(2) Internal design pressure

The internal design pressure at any point in the pipeline system must be equal to or greater than the maximum allowable operating pressure (MAOP). Pressures due to static head of the fluid must be included in the steady-state pressures. Incidental pressures during transient conditions in excess of MAOP are permitted, provided they are of limited frequency and duration, and MAOP is not exceeded by more than 10 %.

NOTE Pressure due to surges, failure of pressure control equipment, and cumulative pressures during activation of over-pressure protection devices are examples of incidental pressures. Pressures caused by heating of blocked-in static fluid are also incidental pressures, provided blocking-in is not a regular operating activity.

(3) Temperature

The range in fluid temperatures during normal operations and anticipated blowdown conditions must be considered when determining temperature-induced loads.

7.3 Environmental loads

(1) Classification

Loads arising from the environment must be classified as environmental, except where they need to be considered as functional (see 7.2) or when, due to a low probability of occurrence, as accidental (see 7.4).

EXEMPLES Loads from waves, currents, tides, wind, snow, ice, earthquake, traffic, fishing and mining are examples of environmental loads. Loads from vibrations of equipment and displacements caused by structures on the ground or seabed are also examples of environmental loads.

(2) Hydrodynamic loads

Hydrodynamic loads must be calculated for the design return periods corresponding to the construction phase and operational phase. The return period for the construction phase must be selected on the basis of the planned construction duration and season and the consequences of the loads associated with these return periods being exceeded. The design return period for the normal operation phase should be not less than three times the design life of the pipeline system or 100 years, whichever is shorter. The joint probability of occurrences in magnitude and direction of extreme winds, waves and currents should be considered when determining hydrodynamic loads. The effect of increases in exposed area due to marine growth or icing shall be taken into account. Loads from vortex shedding shall be considered for aerial crossings and submerged spanning pipeline sections.

(3) Earthquakes

The following effects shall be considered when designing for earthquakes;

1) direction, magnitude and acceleration of fault displacements;
2) flexibility of pipeline to accommodate displacements for the design case;
3) mechanical properties of the carrier pipe under pipeline operating pressure (conditions);
4) design for mitigation of pipeline stresses during displacement caused by soil properties for buried crossings and inertial effects for above-ground fault crossings;
5) induced effects (liquefaction, landslides);
6) mitigation of exposure to surrounding area by pipeline fluids.

(4) Soil and ice loads

The following effects shall be considered when designing for sand loads:

1) sand dune movement;
2) sand encroachment.

The following effects shall be considered when designing for ice loads:

1) ice frozen on pipelines or supporting structures;
2) bottom scouring of ice;
3) drifting ice;
4) impact forces due to thaw of the ice;
5) forces due to expansion of the ice;
6) higher hydrodynamic loads due to increased exposed area;
7) effects added on possible vibration due to vortex shedding.

(5) Road and rail traffic

Maximum traffic axle loads and frequency shall be established in consultation with the appropriate traffic authorities and with recognition of existing and forecast residential, commercial and industrial developments.

7.4 Accidental loads

Loads imposed on the pipeline under unplanned but plausible circumstances must be considered as accidental. Both the probability of occurrence and the likely consequence of an accidental load must be considered when determining whether the pipeline should be designed for an accidental load.

EXAMPLES Loads arising from fire, explosion, sudden decompression, falling objects, transient conditions during landslides, third-party equipment (such as excavators or ship's anchors), loss of power of construction equipment and collisions.

7.5 Combination of loads

When calculating equivalent stresses (see 8.2), or strains, the most unfavorable combination of functional, environmental, construction and accidental loads which can be predicted to occur simultaneously must be considered.

If the operating philosophy is such that operations will be reduced or discontinued under extreme environmental conditions, then the following load combinations must be considered for operations:

1) design environmental loads plus appropriate reduced functional loads;
2) design functional loads and coincidental maximum environmental loads.

Unless they can be reasonably expected to occur together, it is not necessary to consider a combination of accidental loads or accidental loads in combination with extreme environmental loads.

8. Strength requirements--Calculation of stresses

8.1 Hoop stress due to fluid pressure

The circumferential stress, due to fluid pressure only (hoop stress), must be calculated from the following formula:

$$\sigma_{hp} = \left(p_{id} - p_{od}\right)\left(\frac{D_o - t_{\min}}{2t_{\min}}\right)$$

Where

σ_{hp} : circumferential stress due to fluid pressure;
p_{id} : internal design pressure;
p_{od} : minimum external hydrostatic pressure;
D_o : nominal outside diameter:
t_{min} : specified minimum wall thickness.

NOTE: The specified minimum wall thickness is the nominal wall thickness less the allowance for manufacturing per the applicable pipe specification and corrosion. For clad or lined pipelines (see 8.2.3), the strength contribution of the cladding or lining is generally not included.

Carbon steel line pipe must conform to ISO 3183-1, ISO 3183-2 or ISO 3183-3. ISO 3183-2 or ISO 3183-3 line pipe must be used for applications where fracture toughness is required by ISO 13623-8.1.5 and 8.1.6. The design and internal corrosion evaluation must address whether the internal stainless steel or non-ferrous metallic layer must be metallurgically bonded (clad) or may be mechanically bonded (lined) to the outer carbon steel pipe. The minimum thickness of the internal layer must not be less than 3 mm in the pipe and at the weld. The requirement of pipe-end tolerances closer than specified in the appropriate part of ISO 3183 for welding must be reviewed and specified if deemed necessary.

8.2 Other stresses

Circumferential, longitudinal, shear and equivalent stresses must be calculated taking into account stresses from all relevant functional, environmental and construction loads. Accidental loads must be considered as indicated in 7.4. The significance of all parts of the pipeline and all restraints, such as supports, guides and friction, must be considered. When flexibility calculations are performed, linear and angular movements of equipment to which the pipeline has been attached must also be considered. Calculations must take into account flexibility and stress concentration factors of components other than plain straight pipe. Credit may be taken for the extra flexibility of such components. Flexibility calculations must be based on nominal dimensions and the modulus of elasticity at the appropriate temperature(s). Equivalent stresses must be calculated using the von Mises equation as follows:

$$\sigma_{eq} = \left(\sigma_h^2 + \sigma_i^2 - \sigma_h\sigma_i + 3\tau^2\right)^{1/2}$$

Where

σ_{eq} : equivalent stress;
σ_h : circumferential stress;
σ_i : longitudinal stress;
τ : shear stress.

Equivalent stresses may be based on nominal values of diameter and wall thickness. Radial stresses may be neglected when not significant.

9. Minimum thickness (See ASME B31.4—2006 404.1.2)

$$t = \frac{P_i \times D}{2 \times S}$$

Where

t	: pressure design wall thickness ;
Pi	: internal design gage pressure;
D	: outer diameter of pipe
S	: applicable allowable stress value; (0.72×E×SMYS)
E	: weld joint factor.

$$t_n = t + A$$

Where

t_n	: nominal wall thickness satisfying requirements for pressure and allowances;
t	: pressure design wall thickness;
A	: sum of allowances for threading, grooving and corrosion protective measure

10. Strength criteria

10.1 General

Pipelines must be designed for the following mechanical failure modes and deformations:

1) excessive yielding;
2) buckling;
3) fatigue;
4) excessive ovality.

10.2 Yielding

The maximum hoop stress due to fluid pressure must not exceed:

$$\sigma_{hp} \leq F_h \times \sigma_y$$

Where

σ_{hp}	: minimum hoop stress;
Fh	: hoop stress design factor, obtained from Table-6 for pipelines on land and Table-7 for offshore pipelines;
σ_y	: specified minimum yield strength (SMYS) at the maximum design temperature.

NOTE: σ_y should be documented for design temperatures above 50 °C in accordance with 8.1.7.

The mechanical properties at the maximum operating temperature of materials for operations above 50 °C must be documented unless specified in the referenced product standard or complementary justification.

Table- 6: Hoop stress design factors F_h for pipelines on land

Location	F_h
General route (1)	0.77
Crossings and parallel encroachments (2)	
-Minor roads	0.77
-major roads, railways, canals, rivers, diked flood defences and lakes	0.67
Pig traps and multi-pipe slug catchers	0.67
Piping in stations and terminals	0.67
Special constructions such as fabricated assemblies and pipelines on bridges	0.67
The hoop stress factors of following table must apply for category D and E pipelines to be designed to meet the requirements of annex-B. These factors apply to pipelines pressure-tested with water. Lower design factors may be necessary when tested with air.	
(1) The hoop stress factor may be increased to 0.83 for pipelines conveying category C and D fluids at locations subject to infrequent human activity and without permanent human habitation (such as deserts and tundra regions) *(2) See ISO 13623-6.9 for the description of crossings and encroachments.*	

Reference: 6.4.2.2 of ISO 13623-2000

Table- 7: Hoop stress design factors F_h for offshore pipelines

Location	F_h
General route [1]	0.77
Shipping lanes, designated anchoring areas and harbor entrances	0.77
Landfalls	0.67
Pig traps and multi-pipe slug catchers	0.67
Risers and station piping	0.67
(1) The hoop stress factor may be increased to 0.83 for pipelines conveying category C and D fluids.	

Fluid category	D	E			D and E	
Location class	1	1	2	3	4	5
General route	0.83	0.77	0.77	0.67	0.55	0.45
Crossing and parallel encroachments [1]						
- minor roads	0.77	0.77	0.77	0.67	0.55	0.45
- major roads, railway, canals, rivers, diked, flood defenses and lakes	0.67	0.67	0.67	0.67	0.55	0.45
Pig traps and multiple slug catchers	0.67	0.67	0.67	0.67	0.55	0.45
Piping in stations and terminals	0.67	0.67	0.67	0.67	0.55	0.45
Special constructions such as fabricated assemblies and pipelines on bridges	0.67	0.67	0.67	0.67	0.55	0.45
(1) See ISO 13623-Annex B-6.9-2000 for the description of crossings and encroachments.						

Reference: 6.4.2.2 of ISO 13623-2000

The maximum equivalent stress must not exceed.

$$\sigma_{hp} \leq F_h \times \sigma_y$$

Where

- σ_{hp} : minimum hoop stress;
- Fh : equivalent stress design factor, obtained from Table-8.
- σ_y : specified minimum yield strength (SMYS) at the maximum design temperature.

Table- 8: Equivalent stress design factors F_{eq}

Location	F_{eq}
Construction and environmental	1.00
Functional and environmental	0.90
Functional, environmental and accidental	1.00

Reference: 6.4.2.2 of ISO 13623-2000

The criterion for equivalent stress may be replaced by a permissible strain criterion where:

1) the configuration of the pipeline is controlled by imposed deformations or displacements; or
2) the possible pipeline displacements are limited by geometrical constraints before exceeding the permissible strain.

A permissible strain criterion may be applied for the construction of pipelines to determine the allowable bending and straightening associated with reeling, J-tube pull-ups, installation of a bending shoe riser and similar construction methods.

A permissible strain criterion may be used for pipelines in service for:

1) pipeline deformations from predictable non-cyclic displacement of supports, ground or seabed, such as fault movement along the pipeline or differential settlement;
2) non-cyclic deformations where the pipeline will be supported before exceeding the permissible strain, such as in case of a pipeline offshore which is not continuously supported but with sagging limited by the seabed;
3) cyclic functional loads provided that plastic deformation occurs only when the pipeline is first rose to its “worst-case” combination of functional loads and not during subsequent cycling of these loads.

The permissible strain must be determined considering fracture toughness of the material, weld imperfections and previously experienced strain. The possibility of strain localization, such as for concrete-coated pipelines in bending, must be considered when determining strains.

Note: BS 7910 provides guidance for determining the level of permissible strain.

10.3 Buckling

The following buckling modes must be considered:

1) local buckling of the pipe due to external pressure, axial tension or compression, bending and

torsion, or a combination of these loads;

2) buckle propagation;

3) restrained pipe buckling due to axial compressive forces induced by high operating temperatures and pressures.

Note: Restrained pipe buckling can take the form of horizontal snaking for unburied pipelines or vertical upheaval of trenched or buried pipelines.

10.4 Fatigue

Fatigue analyses must be performed on pipeline sections and components that may be subject to fatigue from cyclic loads in order to:

1) demonstrate that initiation of cracking will not occur; or
2) define requirements for inspection for fatigue.

Fatigue analyses must include a prediction of load cycles during construction and operation and a translation of load cycles into nominal stress or strain cycles.

The effect of mean stresses, internal service, external environment, plastic prestrain and rate of cyclic loading must be accounted for when determining fatigue resistance.

Assessment of fatigue resistance may be based on either S-N data obtained on representative components or a fracture mechanics fatigue life assessment.

The selection of safety factors must take into account the inherent inaccuracy of fatigue-resistance predictions and access for inspection for fatigue damage. It may be necessary to monitor the parameters causing fatigue and to control possible fatigue damage accordingly.

10.5 Ovality

Ovality or out-of-roundness that could cause buckling or interference with pigging operations must be avoided.

11. Stability

Pipelines must be designed to prevent horizontal and vertical movement, or must be designed with sufficient flexibility to allow predicted movements within the strength criteria of this International Standard. Factors which must be considered in the stability design include:

1) hydrodynamic and wind loads;
2) axial compressive forces at pipeline bends and lateral forces at branch connections;
3) lateral deflection due to axial compression loads in the pipelines;
4) exposure due to general erosion or local scour;

5) geotechnical conditions including soil instability due to, for example, seismic activity, slope failures, frost heave, thaw settlement and groundwater level;
6) construction method;
7) trenching and/or backfilling techniques.

Note: Stability for pipelines on land can be enhanced by such means as pipe mass selection, anchoring, and control of backfill material, soil cover, soil replacement, drainage, and insulation to avoid frost heave. Possible stability improvement measures for subsea pipelines are pipe mass, mass coating, trenching, burial (including self-burial), gravel or rock dumping, anchoring and the installation of mattresses or saddles.

Article 66-2. Regulation

1. Regulation is a technical requirement which is applied as mandatory rule to facilities, which is determined by a separate legal system in the country. Typical international standards for pipeline are shown in Table-9.

Table- 9: Typical regulation for oil pipeline

Japan		Technical regulation of the thermal power facility
		Technical regulation of the facility for petroleum oil pipeline business
USA	49 CFR 195	Transportation of hazardous liquid by pipeline
Vietnam		

Article 66-3. Allowable stress

1. The pipeline to transport oil and natural gas is required high reliability, since it transports combustible materials. Moreover, not only excellent properties but also the supplies of products which have stable high quality. The grade and allowable stress that is stipulated in API 5L/ISO 3183 is shown in Table-10.

Table-10: Pipeline material stipulated in API 5L/ISO 3183

Grade	YS min. /max. (MPa)	TS min. /max. (MPa)
L245/B	245/ 450	415/ 760
L290/X42	290/ 495	415/ 760
L320/X46	320/ 525	435/ 760
L360/X52	360/ 530	460/ 760
L390/X56	390/ 545	490/ 760
L415/X60	415/ 565	520/ 760
L450/X65	450/ 600	535/ 760
L485/X70	485/ 635	570/ 758

L555/X80	555/ 705	625/ 825
L625/X90	625/ 775	695/915
L690/X100	690/ 840	760/ 990
L830/X120	830/ 1050	915/ 1145

Note: YS: Yield stress, TS: tensile strength

Article 66-4. Applicable standard

1. Standard is a voluntary, reliable and proven standard which is selected to achieve the requirements of regulation, which is one example. Typical international standards for pipeline are shown in Table-11.

Table- 11: Typical standard for oil pipeline

USA	ASME B31.4	Pipeline transportation systems for liquid hydrocarbons and other liquids.
EU	ISO 13623	Petroleum and natural gas industries—Pipeline transportation systems
Australia	AS 2885	A modern standard for design, construction, operation and maintenance of high integrity petroleum pipelines.
Canada	CA Z662	Oil and gas pipeline systems.
UK	BS PD8010	Code of practice for pipeline
Vietnam	TCVN 4090	Main pipelines for transportating oil and oil products. Design standard.

Article 67. Expansion measure for oil pipeline

Article 67-1. Harmful expansion

1. “The equipment to absorb harmful expansion in the place where may cause harmful expansion (hereinafter so called “equipment to absorb expansion”) must be provided as shown in Photo-42, 43, if the heating device is installed, and must be pursuant to as follows;

(1) The bend pipe must be placed in the position where it can be removed the harmful expansion of piping effectively in every 100 meters or less.

(2) The guide must be provided within the area 50 times of the outside diameter of pipe in the opposite side from bent pipe, providing anchor in a side where providing equipment to absorb expansion.

(3) When using expansion joints and the like, pressure strength of it must be more than equal to the strength of the pipe portion of the installation concerned.

Photo- 42: Expansion bend of pipeline

http://www.offshorenet.com/

Photo- 43: Expansion bend of pipeline

http://www.visualphotos.com/image/2x2666136/oil_pipeline_and_heater

Article-68. Joints of oil pipeline, etc.

Article 68-1. Joint of pipeline

1. "The measure to make it possible to check the joints and to prevent spread of dangerous material" must be taken in the place where the dangerous material may scatter outside the premise when leaking from the flange joint which is installed in the premise. And it must be pursuant to as follows;

(1) The check box must have watertight, robust and durable structure with drain valve and lid.

(2) Material of the check box must be used the steel plates with at least 1.6mm thickness.

(3) Corrosion protection measures must be performed by corrosion protection coating.

(4) The check box must not interfere with the structure of piping and the effective depth (distance between bottom of joint and bottom of the check box) must be at least 10cm.

(5) The reservoir must be provided, if the distance from ground level to the lowest point of check box is more than 5cm.

2. Flanged connections

(1) Flanged connections must meet the requirements of ISO 7005-1, or other recognized codes such as ASME B16.5 or MSS SP-44. Proprietary flange designs are permissible. They must conform to relevant sections of ASME Section VIII, Division 1 as shown in Photo-44, 45 and Fig-17.

(2) Compliance with the design requirements of ASME B16.5 must be demonstrated when deviating from the flange dimensions and drillings specified in ASME B16.5 or MSS SP-44.

(3) Consideration must be given to matching the flange bore with the bore of the adjoining pipe wall to facilitate alignment for welding.

(4) Gaskets must be made of materials which are not damaged by the fluid in the pipeline system and must be capable of withstanding the pressures and temperatures to which they will be subjected in

service. Gaskets for services with operating temperatures above 120 °C must be of non-combustible materials.

(5) Bolt material must be in accordance with ASTM A193 B7 or equivalent. Nut material must be in accordance with ASTM A194 2H or equivalent. Bolts or studbolts must completely extend through the nuts.

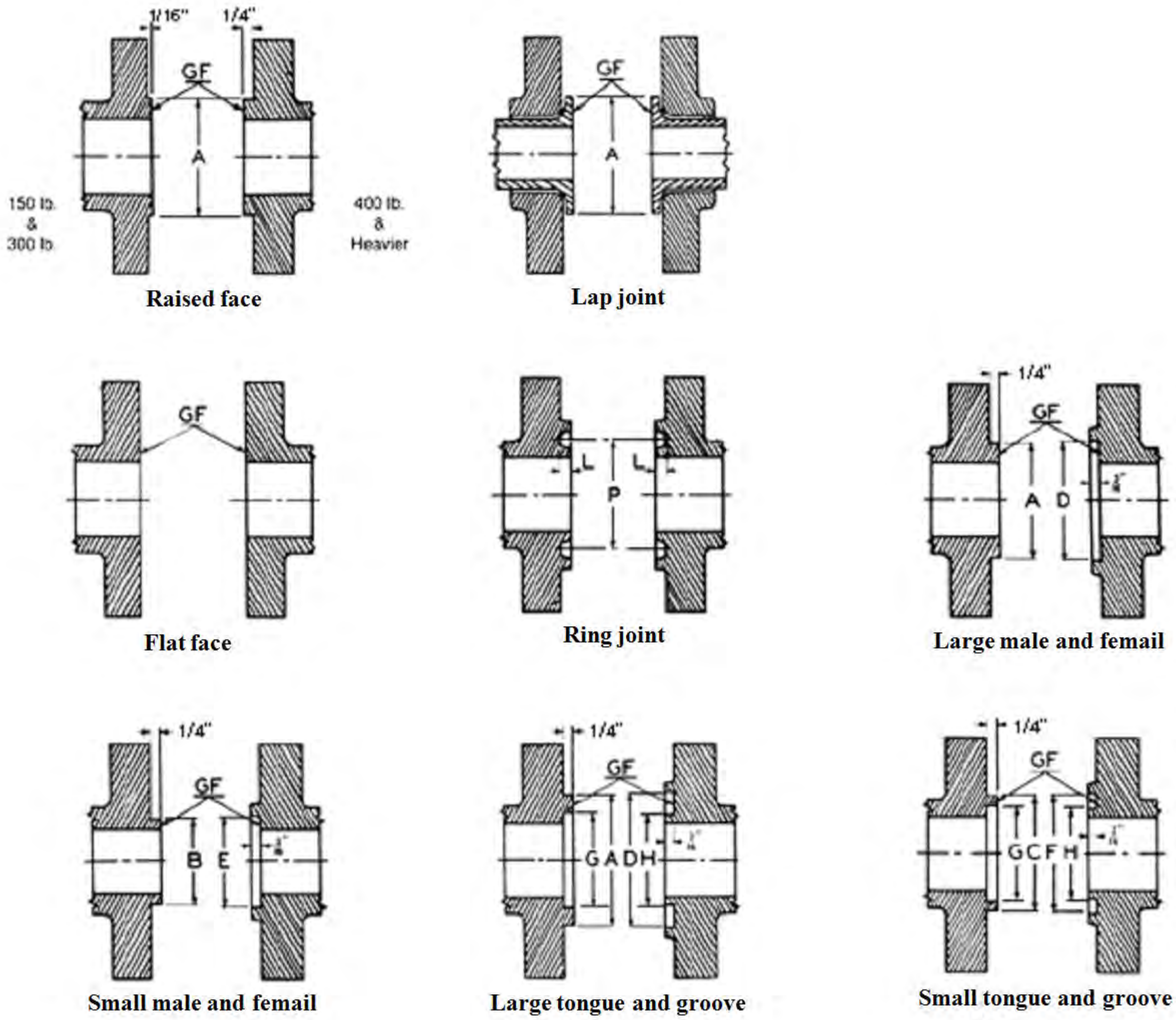


Fig- 17: Steel joint flanges

http://www.rjsales.com/products/ansi_asme_flanges/misc/b.html

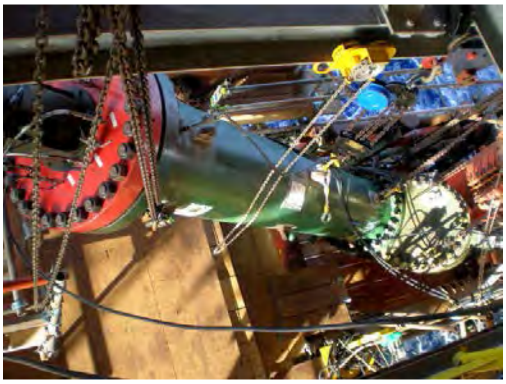


Photo- 44: Flange joint

http://www.offshore-technology.com/contractors/pipeline_inspec/stats-group/stats-group2.html

Photo- 45: Falnge joint

http://gokill.com/2010/06/23/bp-media-and-obama-adminastration-think-americans-are-fools/

Article 68-2. Measure for oil leakage

1. In principle, flange joint must be applied only to piping above ground. However, it applicable to buried piping, if it is unavoidable and it is capable to confirm leakage as shown in Article 85-1.

Article 69. Welding of oil pipeline, etc.

Article 69-1. Welding of pipeline

1. “Welding” must be pursuant to as follows;

(1) Welding of pipeline must be performed according to the proven and reliable international standards such as ISO 13847, API 1104, JIS Z3104, ASME Section-9 or EN 3480.

(2) Welding of pipeline must be performed according to the appropriate WPS.

(3) Welding equipment such as the welding machine, dryer, and windbreak must conform to the welding method or welding conditions specified in WPS.

(4) Welding or consumables such as the welding rod, welding wire, flux, electrode and seal gas must conform to WPS.

(5) A butt weld must be applied for the mains. And V-shape or U-shape groove must be applied to welding joint shape.

Photo-48 shows the arc welding procedure, Photo-46 shows the Tig welding procedure, Photo-47, 49 shows the Mig welding procedure.

Photo- 46: TIG welding

http://www.ukwelder.com/forum/lofiversion/index.php/t4240.html

Photo- 47: MIG welding

http://www.magnatech-lp.com/articles/onemillion.htm

Photo- 48: Arc welding

http://www.gazprom.com/production/projects/pipelines/mvkk/

Photo- 49: MIG welding

http://www.fronius.com/cps/rde/xchg/SID-10999EBE-0044722D/fronius_international/hs.xsl/79_11684_ENG_HTML.htm

Article 69-2. Welding equipment and consumables

Photo- 50: Auto TIG welding machine

http://www.alibaba.com/product-gs/202191836/AUTOMATIC_PIPE_WELDING_MACHINE_ORBITAL_PIPE.html

Photo- 51: Auto TIG welding machine

http://www.thefabricator.com/article/tubepipefabrication/welding-more-with-less

1. Welding of pipeline must be performed according to the appropriate WPS.
2. Welding equipment such as the welding machine, dryer and windbreak must conform to the welding method or welding conditions specified in WPS. Photo-50, 51 shows Tig welding equipment.
3. Welding consumables such as the welding rod, welding wire, flux, electrode, seal gas must conform to WPS.

Article 70. Anti-corrosion coating of oil pipeline

1. Corrosion protection methods are classified into 4 types, the anti-corrosion coating method, the electric protection method, the application of corrosion resistant material, the environmental control. It must be selected in consideration of anti-corrosion effect, cost, workability, maintenanceability and the like.

Article 70-1. Protection for pipeline in the sea or on seabed

1. Corrosion protection coating

   Painting coating by polyethylene, polypropylene, coal-tar enamel and the like is applied to prevent exterior corrosion of pipeline as well as the pipeline on the land or underground as shown in Photo-52
2. Cathodic protection

   Submarine pipelines are pipelines installed under water that are resting on seabed. Submarine pipelines can be divided into three different groups.

   1) offshore pipelines
   2) coastal submarine pipelines
   3) deepwater pipelines.

   In general, the low and uniform resistivity of seawater simplifies the operation of cathodic protection systems for submarine pipelines. The current demand in different seawater locations varies upon temperature, salinity, and depth. For the majority of situations, the critical factor is water temperature. Sacrificial anodes in bracelet shapes are the most preferable type of cathodic protection application for offshore pipelines. These sacrificial anodes are typically applied as “bracelets” and are installed at certain intervals along a new line as shown in Photo-53. The standard materials for bracelet anodes are Aluminum-zinc-indium; however, zinc anodes are also used occasionally.

   The use of zinc bracelet anodes is not recommended as applications where the pipeline surface can reach temperatures higher than 50 ^{o}C. For elevated pipeline temperatures, we recommend using sled anodes, or anode beds, which are placed alongside the pipeline and are connected with a cable. It is also recommended to apply thermo-insulation inside the anodes using adhesive glue.

In order to provide adequate cathodic protection of the pipelines, sufficient direct current must be supplied on the external pipe surface, so that the steel-to-electrolyte potential is reduced to values at which external corrosion occurs at a minimal rate.

Cathodic protection is used in combination with a suitable coating system to protect the external surfaces of steel pipelines against corrosion.

Photo- 52: Coated offshore pipeline

http://pipeliner.com.au/news/fresh_wave_of_projects_buoy_offshore_pipeline_industry/001619/

Photo- 53: Deepwater cathodic protection

http://www.stoprust.com/prb4.htm

Article 70-2. Protection for pipeline on the land or underground

1. Generally, the constant length pipe which is performed anti-corrosion coating as shown in Photo-57 is used for pipeline and corrosion protection measures carried out after non-destructive testing and repair welding at site.
2. Painting coating by polyethylene, polypropylene, coal-tar enamel and the like is applied to prevent exterior corrosion of pipeline as shown in Photo-54, 55, 56.
3. Field Joint Coating

   The coating of the pipeline field joints to prevent corrosion starts a few days after the welding. This extended period is to allow for any repairs or cut-outs to be completed without prejudicing the coating crew's operation.

Photo- 54: Corrosion protection taping

http://neftegaz.ru/en/news/tag/pipeline/2

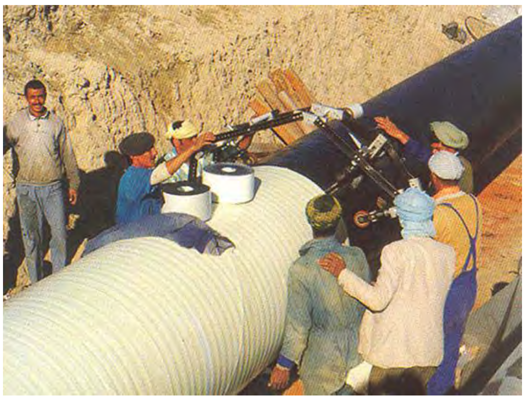


Photo- 55: Corrosion protection taping

http://www.made-in-china.com/showroom/sdxunda/product-detailnowmyqJvhtYb/China-Polyethylene-Corrosion-Protection-Tape-for-Gas-Oil-Pipelines.html

Photo- 56: Corrosion protection taping

http://aikongu.blog96.fc2.com/

Photo- 57: Fusion bonded epoxy powder coating

http://www.brederonigeria.com/products/fbe/

Article 71. Electric protection of oil pipeline, etc.

Article 71-1. Protection for pipeline underground or on seabed

1. Cathodic protection

1.1 Cathodic protection potentials

Cathodic protection potentials must be maintained within the limits given in Table-12 throughout the design life of the pipeline.

Table- 12: Cathodic protection potentials for non-alloyed and low –alloyed pipelines

Reference electrode		$Cu/CuSO_4$	Ag/AgCl/Seawater
Water and low-resistivity soil Resistivity < 100Ωm	Aerobic $T < 40^{\circ}C$	-0.850V	-0.800V
	Aerobic $T > 60^{\circ}C$	-0.950V	-0.900V
	Aerobic	-0.950V	-0.900V
High-resistivity aerated sandy soil regions	Resistivity 100Ωm to 1000Ωm	-0.750V	-0.700V
	Resistivity >1000Ωm	-0.650V	-0.600V

Note-1: Potentials in this Table and in NOTE 4 apply to line pipe materials with actual yield strengths of 605 MPa or less.

Note-2: The possibility for hydrogen embrittlement must be evaluated for steels with actual yield strengths above 605 MPa.

Note-3: For all steels the hardness of longitudinal and girth welds and their implications for hydrogen embrittlement under cathodic protection must be considered.

Note-4: The protection potential at the metal-medium interface must not be more negative than –1,150 V in case of Cu/CuSO4 reference electrodes, and –1,100 V in case of Ag/AgCI reference electrodes. More negative values are acceptable provided it is demonstrated that hydrogen embrittlement damage cannot occur.

Note-5: The required protection potentials for stainless steels vary. However, the protection potentials shown above can be used. For duplex stainless steels used for pipelines, extreme care must be taken to avoid voltage overprotection which could lead to hydrogen-induced failures.

Note-6: If the protection levels for low-resistivity soils cannot be met, then these values may be used subject to proof of the high-resistance conditions.

Note-7: Alternative protection criteria may be applied provided it is demonstrated that the same level of protection against external corrosion is provided.

Note-8: The values used must be more negative than those shown within the constraints of the NOTES 1 to 7. The protection potential criteria shown in Table-12 apply to the metal-medium interface. In the absence of interference currents this potential corresponds to the instantaneous "off" potential.

Reference: 9.5.3.1 of ISO 13623-2000

1.2 Design

The current density must be appropriate for the pipeline temperature, the selected coating, the environment to which the pipeline is exposed and other external conditions which can affect current demand. Coating degradation, coating damage during construction and from third-party activities, and metal exposure over the design life must be predicted and taken into account when determining the design current densities.

(1) Sacrificial anodes

The design of sacrificial anode protection systems must be documented and include reference to:

1) pipeline design life (see ISO 13623-5.1);
2) design criteria and environmental conditions;
3) applicable standards;
4) requirements for electrical isolation;
5) calculations of the pipeline area to be protected;
6) performance of the anode material in the design temperature range;
7) number and design of the anodes and their distribution;
8) protection against the effects of possible a.c. and/or d.c. electrical interference.

(2) Impressed current

The design of impressed-current protection systems must strive for a uniform current distribution along the pipeline and must define the permanent locations for the measurement of the protection potentials (see ISO 13623-9.5.3.3). Design documentation must at least include reference to:

1) pipeline design life (see ISO 13623-5.1);
2) design criteria and environmental conditions;
3) requirements for electrical isolation;
4) calculations of the pipeline area to be protected;
5) anode ground bed design, its current capacity and resistance and the proposed cable installation and protection methods;
6) measures required to mitigate the effects of possible a.c. and/or d.c. electrical interference;
7) protection requirements prior to the commissioning of the impressed current system;
8) applicable standards.

(3) Connections

Cathodic protection anodes and cables must be joined to the pipeline by connections with a metallurgical bond. The design of the connections must consider:

1) the requirements for adequate electrical conductivity;
2) the requirements for adequate mechanical strength and protection against potential damage during construction;
3) the metallurgical effects of heating the line pipe during bonding. The use of double plates must be considered when connecting anodes and cables to stainless steel pipelines. Possible interference by extraneous d.c. current sources in the vicinity of a pipeline and the possible effect of the protection of a new pipeline on existing protection systems must be evaluated. The shielding by thermal insulation and possible adverse effects of stray currents from other sources must be evaluated when considering cathodic protection systems for insulated pipelines.

1.3 Specific requirements for pipelines on land

Cathodic protection must normally be provided by impressed current.

Note-1: Sacrificial anode protection systems are normally only practical for pipelines with a high-quality coating in low resistivity environments. The suitability of backfill material at anode locations should be reviewed. Protected pipelines must, where practical, be electrically isolated from other structures, such as compressor stations and terminals, by suitable in-line isolation components. Isolating joints must be provided with protective devices if damage from lightning or high-voltage earth currents is possible. Low-resistance grounding to other buried metallic structures must be avoided.

Note-2: It is recommended that the pipeline be isolated from structures, such as wall entries and restraints made of reinforced concrete, from the earthing conductors of electrically operated equipment and from bridges. The possibility for corrosion on the unprotected sides of isolating couplings must be considered when low resistance electrolytes exist internally or *externally. Electrical continuity must be provided across components, other than couplings/flanges, which would otherwise increase the longitudinal resistance of the pipeline.*

The corrosion protection requirements of pipeline sections within sleeve or casing pipe must be identified and applied.

Spark gaps must be installed between protected pipelines and lightning protection systems.

If personnel safety is at risk or if an a.c. corrosion risk exists, unacceptably high a.c. voltages on a pipeline must be prevented by providing suitable earthing devices between the pipeline and earthing systems without impacting on the cathodic protection.

Test points for the routine monitoring and testing of the cathodic protection must be installed at the following locations:

1) crossings with d.c. traction systems;
2) road, rail and river crossings and large embankments;
3) sections installed in sleeve pipes or casings;
4) isolating couplings;
5) where pipelines run parallel to high-voltage cables;
6) sheet piles;
7) crossings with other major metallic structures with, or without, cathodic protection.

Additional test points, regularly spaced along the pipeline, must be considered to enable cathodic protection measurements to be taken for the entire pipeline route.

Note-3: The required test spacing depends on soil conditions, terrain and location.

1.4 Specific requirements for offshore pipelines

Cathodic protection must be by sacrificial anodes.

Note: Experience has indicated that sacrificial anodes provide effective protection with minimum requirements for maintenance. Electrical isolation is not typically provided between an offshore pipeline and its metallic support structure.

However, electrical isolation may be provided between an offshore pipeline and connected metallic structures or other pipelines to allow the separate design and testing of the corrosion protection systems. The cathodic protection of individual pipelines and structures shall be compatible if isolation is not provided. Cathodic protection measurement points and techniques for offshore pipelines must be selected to provide representative measurements of the cathodic protection levels.

Design of sacrificial anodes should be consistent with the pipeline construction method and *the requirements associated with lay-barge tensioning equipment. Anode locations associated with pipeline crossings require special attention.*

Article 71-2. Protection for adjacent structures

1. Steel structure in seawater or damp ground is subceptible to corrosion and in an environmental prone to rust. Rust cause on the rebar even inside the concrete structure. Therefore, the technology which is called "cathodic protection" is used to stop corrosion as shown in Fig-18. There are two methods for the cathodic protection. One is "sacrificial anode method" to bridge metal as the sacrifice electrode which has bigger tendency than iron as shown in Fig-19, 20. The corrosion of iron in aqueous solution is due to the local cell action that the iron dissolves as iron cations and discharged electrons flows as corrosion current. So, when installing the aluminum electrode on iron structure in the water, corrosion of iron structure can be prevented, since aluminum is dissolved as sacrificial electrode. In case of galvanized tin, iron does not generate rust by means of dissolving the zinc which has large ionization tendency.
2. The other is the method which is called "external electrode method" as shown in Fig 21 and Photo-58. This is the method to negate the corrosion current by means of applying DC current in the opposite direction of the local cell action of the iron structure. This "external electrode method" has been used widely in the bridge girder for seawall and harbor structures.

   "External electrode method" uses the auxiliary electrode as the anode to flow currents. The ferrite which is mainly composed iron oxide is cheep and has excellent corrosion resistance, high safety and reliability. Ferrite electrode is an electrode material with excellent characteristics of resistivity and special ceramic crystal uniformity.

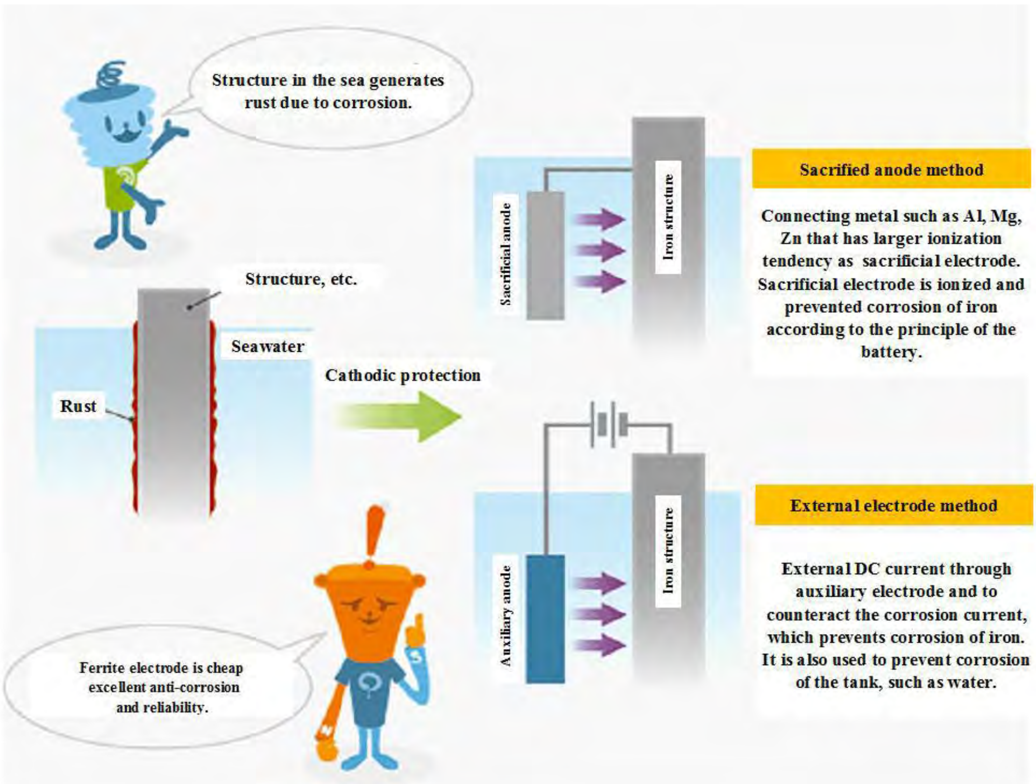


Fig- 18: The principle of cathodic protection

http://www.tdk.co.jp/techmag/inductive/200711/index2.htm

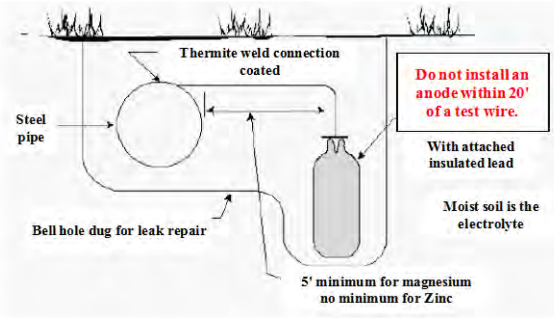


Fig- 19: Sacrificial anode method

http://windot.com/freeregs/smallops/mergedProjects/Natgas/ch3/chapter_iii_principles_and_practices_of_cathodic_protection.htm

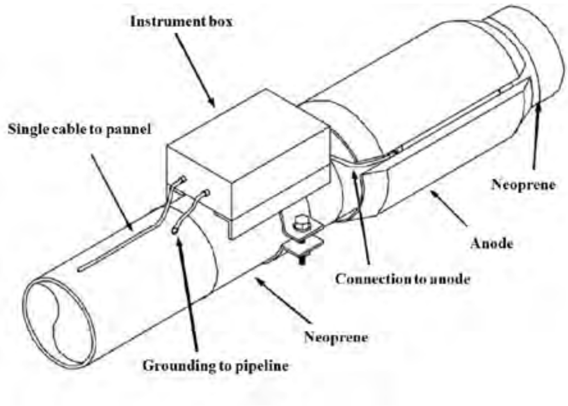


Fig- 20: Sacrificial anode method

http://www.stoprust.com/18arcticcpmonitoring.htm

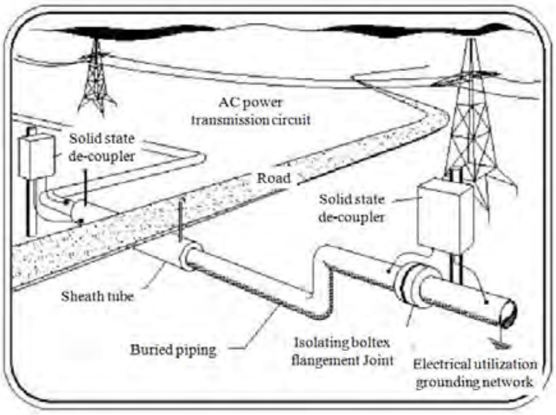


Fig- 21: External electrode metod

http://www.cathodic.co.uk/information/13/17/Rustrol_Cathodic_Isolators.htm

Photo- 58: Outer electricity cabinet

http://www.tgpl.cojp/business_02.html

Article 72. Heating and insulation for oil pipeline

Article 72-1. Space heating

1. When providing the heating and insulation equipment for piping and the like as shown in Fig-22 and Photo-59, it must be pursuant as follows;

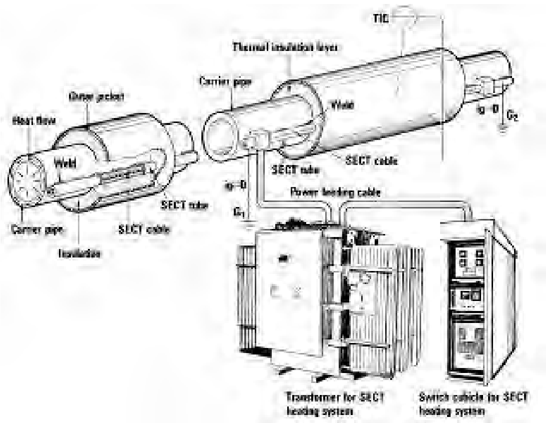


Fig- 22: Space heating system

http://www.jnc-eng.com/cn20/pg260.html

Photo- 59: Trace heater for heavy oil

http://www.processindustryinformer.com/Editorial-Feature-Archive/APPLYING-THE-HEAT-AN-OVERVIEW-OF-INDUSTRIAL-HEAT-TRACING

(1) The insulation material which is used for exterior worm and cold insulation must be non-combustible material or equivalent, and covered with steel plates to prevent intrusion of rainwater.

(2) The piping which is provided heating equipment must install a temperature detection device and operation condition, etc. can be monitored in the place where it is shown remotely at all times.

(3) The piping which has double tube heating equipment must have materials and construction which is hard to occur displacement due to expansion and contraction of piping.

(4) Heating or insulation equipment must be installed without adverse effect against corrosion measure for piping

(5) The heating equipment must have the construction which temperature does not rise abnormally and locally.

(6) The heat source for the heating equipment must be steam or hot water in principle. However, if electricity is unavoidable because of the work process, it must be pursuant as follows;

1) It must have the construction which is capable to automatically shut-off the heating equipment in conjunction with alarm in the emergency case such as short circuit, over-current and overheating.

2) The heating equipment must have structure so that it does not melt or eliminate easily in the mounting portion.

Article 73. Installation site of oil pipeline

Article 73-1. Installation on the ground

1. Pipeline spanning

Spans in pipelines must be controlled to ensure compliance with the strength criteria in Table-13.

Due consideration must be given to:

1) support conditions;
2) interaction with adjacent spans;
3) possible vibrations induced by wind, current and waves;
4) axial force in the pipeline;
5) soil accretion and erosion;
6) possible effects from third-party activities;
7) soil properties.

2. Support

The typical support of pipeline is shown in Fig-23 and Photo-60, 61

(1) Support span

Table- 13: Suggested pipe support spacing (ASME B31.1-2004)

Nominal pipe size	Suggested maximum span			
	Water service		Steam, gas or air service	
NPS	(ft)	(m)	(ft)	(m)
1	7	2.1	9	2.7
2	10	3.0	13	4.0
3	12	3.7	15	4.6
4	14	4.3	17	5.2
6	17	5.2	21	6.4
8	19	5.8	24	7.3
12	23	7.0	30	9.1
16	27	8.2	35	10.7
20	30	9.1	39	11.9
24	32	9.8	42	12.8

Photo- 60: Pipeline on the ground

http://www.discoveringthearctic.org.uk/7_natures_riches.html

Photo- 61: Pipeline on the ground

http://pubs.usgs.gov/fs/2003/fs014-03/pipeline.html

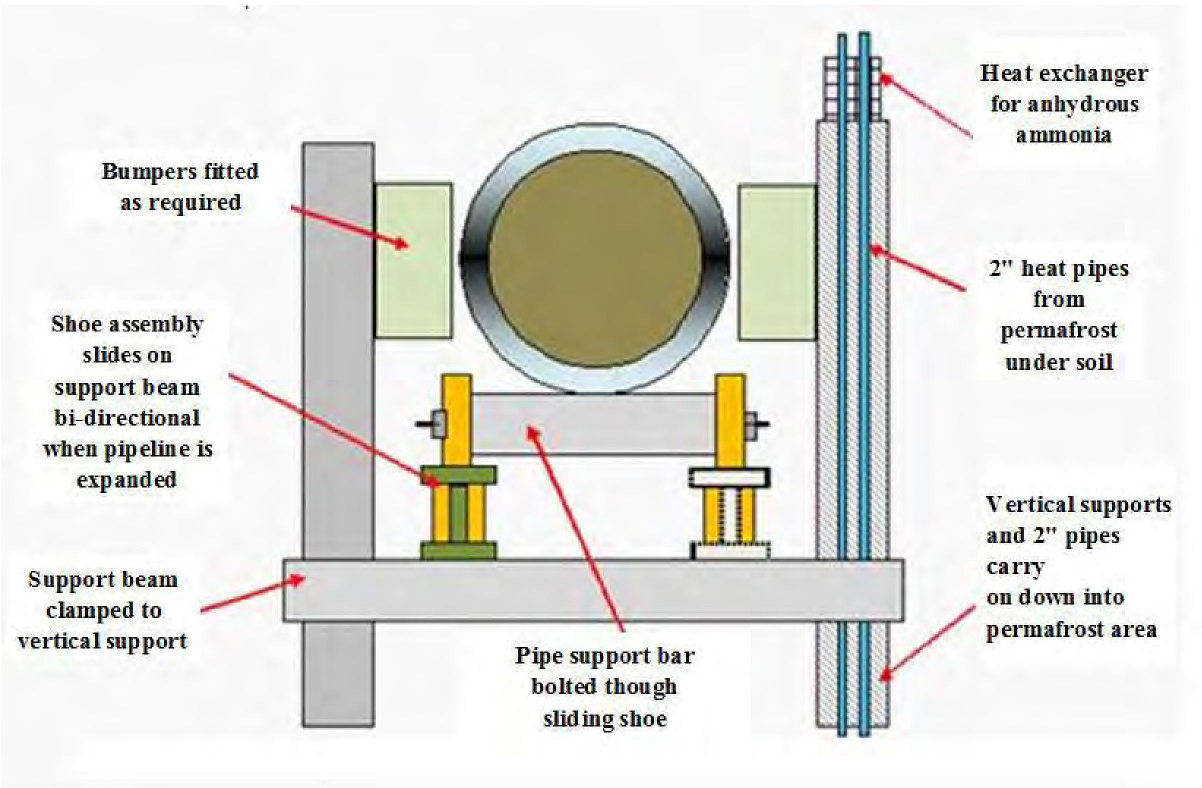


Fig- 23: Pipeline on the ground

http://www.brighthub.com/engineering/mechanical/articles/84796.aspx

2. Pipeline right of way

A *right-of-way* (ROW) as shown in Fig-24is a strip of land usually between 18 meters (60 feet) and 36 meters (120 feet) wide, containing one or more pipelines. The ROW:

1) Allows workers access for inspection, maintenance, testing or in an emergency.
2) Identifies an area where certain activities are prohibited to protect public safety and the integrity of the pipeline.

While permanent pipeline markers are located at roads, railways and other intervals along the ROW, these show only the approximate location of the buried pipelines. The depth and location of the pipelines vary within the ROW. The ROW exists in many kinds of ecosystems from river crossings and cultivated fields to sub-Arctic tundra and urban areas. Because of this, there is no distinct look to the ROW. Pipeline rights-of-way are acquired from landowners, other utilities or government entities by obtaining an easement, permit, license, or, in limited cases, through purchase.

1) Pipeline right-of-way must be selected to avoid, as far as practicable, areas containing private dwellings, industrial buildings, and places of public assembly.

2) No pipeline may be located within 50 feet (15 meters) of any private dwelling, or any industrial building or place of public assembly in which persons work, congregate, or assemble, unless it is provided with at least 12 inches (305 millimeters) of cover.

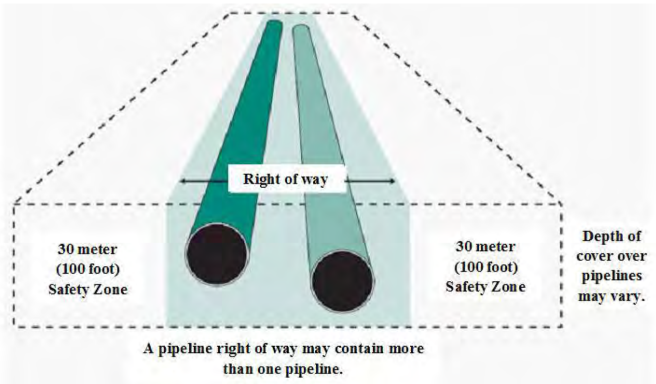


Fig- 24: Concept of right of way

https://www.neb-one.gc.ca/clf-nsi/rsftyndthnvrnmnt/sfty/rfrncmtrl/xcvtnndcnstrctnnrppln-eng.html

Article 74 Underground installation of oil pipeline

Article 74-1. Underground installation

1. Piping cover for Pipelines on land

Buried pipelines on land should be installed with a cover depth not less than shown in Table-14.

Table- 14: Minimum cover depth for pipelines on land (ISO 13623-2009)

Location	Cover depth (m)
Areas of limited or no human activity	0.8
Agricultural or horticultural activity (1)	0.8
Canal, rivers (2)	1.2
Roads and railways (3)	1.2
Residential, industrial and commercial areas	1.2
Rocky ground (4)	0.5
Cover depth must be measured from the lowest possible ground surface level to the top of the pipe, including coatings and attachments. Special consideration for cover may be required in areas with frost heave.	
(1) : Cover must not be less than the depth of normal cultivation. *(2) : To be measured from the lowest anticipated bed.* *(3) : To be measured from the bottom of the drain ditches.* *(4) : The top of pipe must be at least 0.15m below the surface of the rock.*	

Reference: 6.8.2.1 of ISO 13623-2000

Pipelines may be installed with less cover depth than indicated in Table-13, provided a similar level of protection is provided by alternative methods. The design of alternative protection methods must take into account as shown in Fig-25, Photo-62, 63, 64:

1) any hindrance caused to other users of the area;
2) soil stability and settlement;
3) pipeline stability;
4) cathodic protection;
5) pipeline expansion;
6) access for maintenance.

Photo- 62: Underground pipeline

http://www.pnnl.gov/science/highlights/highlight.asp?id=537

Photo- 63: Underground pipeline

http://fuelfix.com/blog/2011/07/11/15-companies-snare-crude-from-reserve/

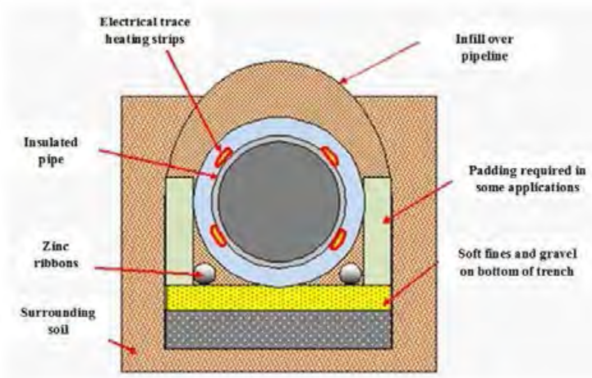


Fig- 25: Underground pipeline

http://www.brighthub.com/engineering/mechanical/articles/84796.aspx

Photo- 64: Underground pipeline

http://www.zimbio.com/pictures/oQus0Q4vsyk/Oil+Pipeline+Spill+Contaminates+Waters+Salt/vvRFR7EqiP5

Article 75. Oil pipeline, etc. installation buried under road

Article 75-1. Installation under the road

1. Roads must be classified as major or minor for the application of the hoop stress design factor.

Motorways and trunk roads must be classified as major and all other public roads as minor. Private roads or tracks must be classified as minor even if used by heavy vehicles. The hoop stress design factors in Table-6 and the cover depth requirements in Table-14 must, as a minimum, apply to the road right-of-way boundary or, if this boundary has not been defined, to 10 m from the edge of the hard surface of major roads and 5 m for minor roads. Pipelines running parallel to a road must be routed outside the road right-of-way boundary where practicable.

Photo- 65: Pipeline buried under road

http://www.cleaner.com/editorial/2011/02/leading-the-charge

Photo- 66: Pipeline buried under road

http://eastcountymagazine.org/node/4626

Article 76. Oil pipeline, etc. installed buried under rail road

Article 76-1. Installation buried under the rail road

1. The hoop stress design factors in Table-6 and the cover depth requirements in Table-14 must, as a minimum, apply to 5 m beyond the railway boundary or, if the boundary has not been defined, to 10 m from the rail. Pipelines running parallel to the railway must be routed outside the railway right-of-way where practicable. The vertical separation between the top of the pipe and the top of the rail must be a minimum of 1.4 m for open-cut crossings and 1.8 m for bored or tunneled crossings

Photo- 67: Pipeline under railroad

http://www.lachel.com/projects/water-wastewater-infrastructure/linden-cso/

Photo- 68: Sheath tube under railroad

http://www.kanapipeline.com/images/tunnel-bore.html

Article 77. Oil pipeline, etc.installed buried in the regional river conservation

Article 77-1. Installation buried in the regional river conservation

1. It is not allowed to place pipeline in the dry riverbed or river bank along the river, although it is allowed to traverse above or under the river by burring, sheath tube or culvert.
2. The shutoff valve must be installed on both side of the river when crossing the river with over 30m width.

Article 78. Onshore installation oil pipeline, etc.

Article 78-1. Installation above the ground

1. If the pipeline or the pipe support (hereinafter “pipeline support”) may be damaged, the protective equipment must be pursuant as follows;

(1) When vehicle, etc. passes the side of pipe support and the like, the protective equipment (herein after “side protective equipment”) must conform to the followings pursuant to Fig-26;

1) The side protective equipment must be reinforced concrete and the like. However, it may be a metal guardrail when installing it in the premises.
2) The height of the side protective equipment must be at least 0.8m from the ground surface.
3) The space between pipe support and side protection equipment must be at least 1/2 of the height of the said protective equipment.

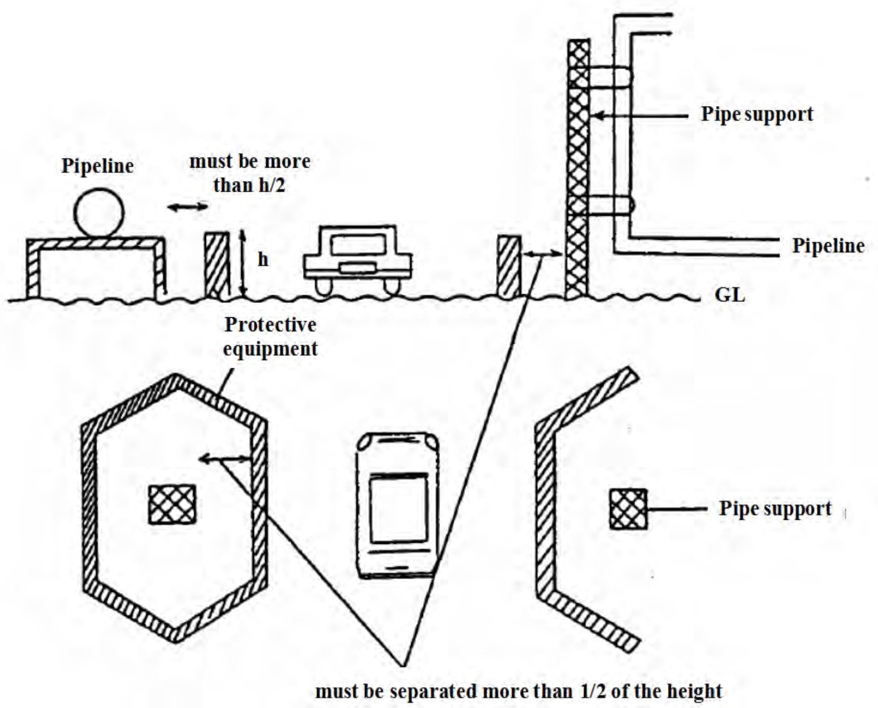


Fig- 26: Side protective equipment for pipeline

Reference: Regulation for the transportation and handling station of hazardous materials (Dec. /2011):

Ministry of Internal Affairs and Communications Japan)

(2) When vehicle passes under the pipe support, the protective equipment for aerial pipeline (hereinafter so called "upper protective equipment") must be provided pursuant as follows other than the standard stipulated in (1) as shown in Fig-27.

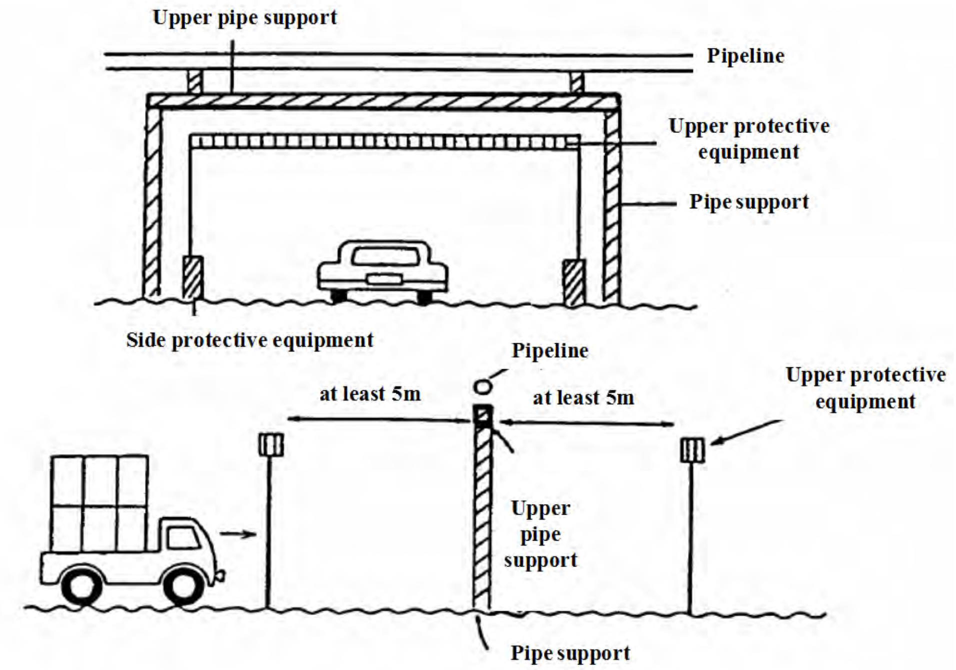


Fig- 27: Upper protective equipment for pipeline

Reference: Regulation for the transportation and handling station of hazardous materials (Dec. /2011): Ministry of Internal Affairs and Communications Japan)

1) The upper protective equipment must be installed below the bottom of pipe support, provided in the opposite direction of vehicle and installed so as not to damage such support.
2) If the upper protective equipments not provided at the entrance of said premises, it may not be installed in the premise.
3) The upper protective equipment must have non-combustible materials.
4) The upper protective equipment may not place, if vertical distance between bottom of pipe support and ground surface is more than 5m.

(3) When installing pipeline support on the pier and the like, the fender for cushion must be provided to prevent damage to said support, etc. when floating objects and vessels collide with the pier. However, the protection equipment for floating object may not provided when the construction of pier is truss by column and is monolithic as shown in Fig 28.

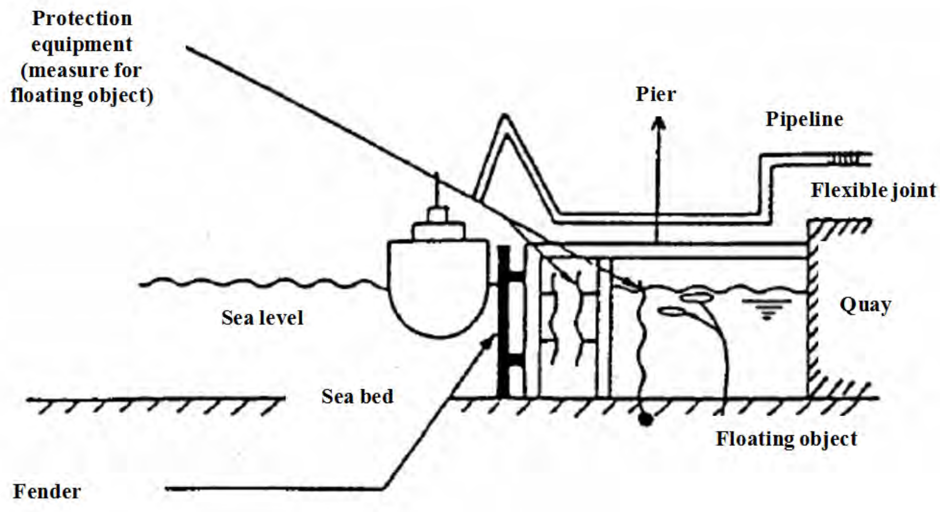


Fig- 28: Construction of pier

Reference: Regulation for the transportation and handling station of hazardous materials (Dec. /2011):

Ministry of Internal Affairs and Communications Japan)

Article 79. Subsea installation of oil pipeline, etc

Article 79-1. Installation on the seabed

1. The large tankers have about 20m draft, which hull will run on the ground in shallow waters. Therefore, oil is transported using underwater piping, marine hose or receiving pipe on the pie after unloading at the sea berth which is located in offshore deep water location. The pipeline which is installed on the seabed is the oil transportation undersea pipeline.
2. It may place pipeline directly on the seabed in the location where there is no possibility of damage by anchors, however, protection by weight or burring must be considered if there is possibility of damage and floating as shown in Fig-29, 30, 31, Photo-69, 70 and 71.

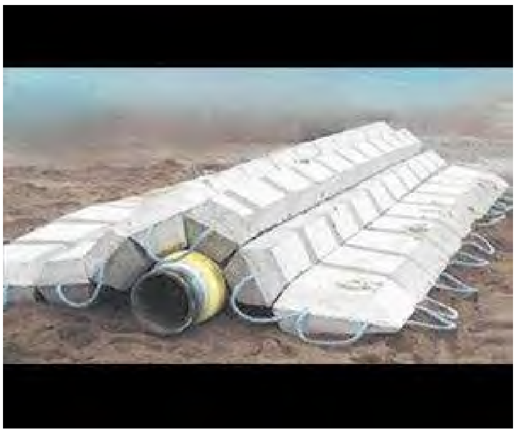


Fig- 29: Pipeline on the seabed

http://www.pressandjournal.co.uk/Article.aspx/2400930

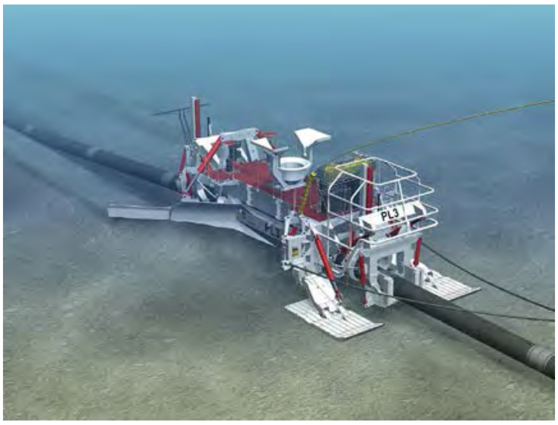


Fig- 30: Pipeline on the seabed

http://www.nord-stream.com/press-info/images/the-pl3-plough-2889/?category=113&sub_category=122

Photo- 69: Offsore pipeline for crude oil

http://www.kk-jasco.co.jp/gyoumu01.html

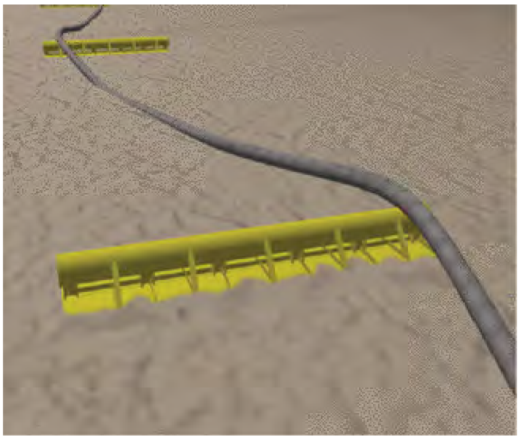


Fig- 31: Pipeline on the seabed

http://www.pennenergy.com/index/petroleum/display/239263/articles/offshore/volume-65/issue-10/pipeline-transportation/designed-buckling-for-hp-ht-pipelines.html

Photo- 70: Pipeline on the seabed

http://heatland.cn/en/case1.html

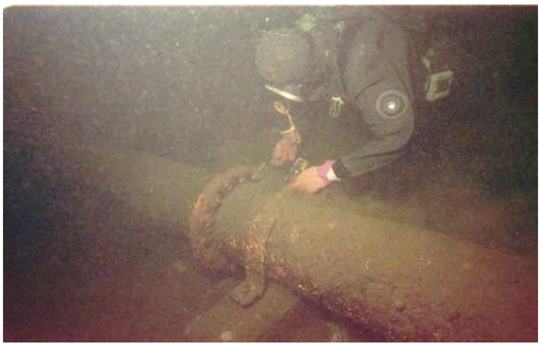


Photo- 71: Pipeline on the seabed

http://homepage3.nifty.com/takedive/page11.htm

3. Adverse ground and seabed conditions

Where necessary, protective measures, including requirements for surveillance shall be established to minimize the occurrence of pipeline damage from adverse ground and seabed conditions.

Examples: Adverse ground and seabed conditions include landslide, erosion, subsidence, differential settlement, areas subject to frost heave and thaw settlement, peat areas with a high groundwater table and swamps. Possible protective measures are increased pipe wall thickness, ground stabilization, erosion prevention, installation of anchors, provision of negative buoyancy, etc., as well as surveillance measures. Measurements of ground movement, pipeline displacement or change in pipeline stresses are possible surveillance methods. Local authorities, local geological institutions and mining consultants should be consulted on general geological conditions, landslide and settlement areas, and tunneling and possible adverse ground conditions.

Article 80. Offshore installation of oil pipeline, etc.

Article 80-1. Installation in the sea

1. Offshore pipelines

   Offshore pipelines shall be trenched, buried or protected if external damage affecting the integrity is likely, and where necessary to prevent or reduce interference with other activities. Other users of the area shall be consulted when determining the requirements for reducing or preventing this interference. Protective structures for use on offshore pipelines should present a smooth profile to minimize risks of snagging and damage from anchoring cables and fishing gear. They should also have sufficient clearance from the pipeline system to permit access where required, and to allow both pipeline expansion and settlement of the structure foundations. The design of the cathodic protection of the pipeline should be compatible with that of any connecting structure.

2. A minimum vertical separation of 0.3m must be kept between the pipeline and any other underwater structures such as existing pipelines and submarine cables. Mats or equivalent means must be used for positive separation at crossing locations.

Article 81. Oil pipeline, etc. installation across the road

Article 81-1. Installation across the load

1. Roads must be classified as major or minor for the application of the hoop stress design factor. Motorways and trunk roads must be classified as major and all other public roads as minor. Private roads or tracks must be classified as minor even if used by heavy vehicles. The hoop stress design factors in Table-6 and the cover depth requirements in Table-7 must, as a minimum, apply to the road right-of-way boundary or, if this boundary has not been defined, to 10 m from the edge of the hard surface of major roads and 5 m for minor roads. Pipelines running parallel to a road must be routed outside the road right-of-way boundary where practicable. Fig-32, Photo-72, 73 and 74 shows typical crossing the road of pipeline.

Photo- 72: Road crossing pipeline

http://www.panoramio.com/photo/22228553

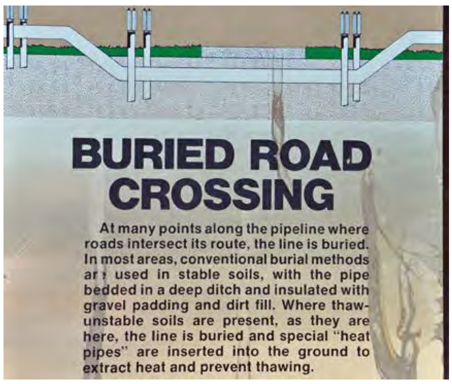


Fig- 32: Buried pipeline under the road

http://pipelineintegrity.wordpress.com/category/pipeline-engineering/

Photo- 73: Buried pipeline under the road

http://www.cabeceo.net/?page_id=195

Photo- 74: Buried pipeline under the road

http://wsipsunolvalley.blogspot.com/2010/08/pipeline-construction-on-calaveras-road.html

Article 82. Oil pipeline, etc. installation across the rail road

Article 82-1. Installation across the rail road

1. The pipe at each railroad or highway crossing must be installed so as to adequately withstand the dynamic forces exerted by anticipated traffic loads as shown in Fig-33 and Photo-75.

Photo- 75: Pipeline below railroad

http://www.iowatrenchless.com/piperamming.html

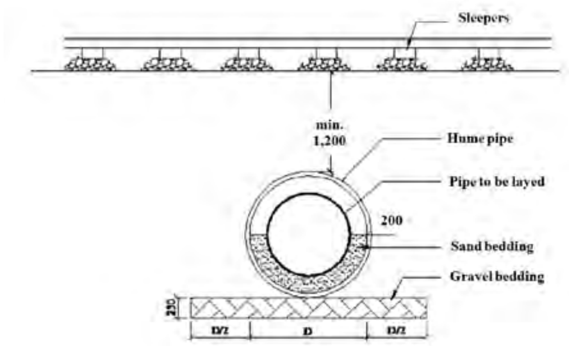


Fig- 33: Pipeline below railroad

http://goda02.com/pipe-laying-procedures

2. The hoop stress design factors in Table-6 and the cover depth requirements in Table-7 must, as a minimum, apply to 5 m beyond the railway boundary or, if the boundary has not been defined, to 10 m from the rail. Pipelines running parallel to the railway must be routed outside the railway right-of-way where practicable. The vertical separation between the top of the pipe and the top of the rail must be a minimum of 1.4 m for open-cut crossings and 1.8 m for bored or tunneled crossings.

Article 83. Oil pipeline, etc. installation across the river

Article 83-1. Installation across the river

1. Waterways and landfalls

   Protection requirements for pipeline crossings of canals, shipping channels, rivers, lakes and landfalls must be designed in consultation with the water and waterways authorities. Crossings of flood defenses can require additional design measures for the prevention of flooding and limiting the possible consequences as shown in Photo-76, 77. The potential for pipeline damage by ships' anchors, scour and tidal effects, differential soil settlement or subsidence, and any future works such as dredging, deepening and widening of the river or canal, must be considered when defining the protection requirements.

Photo- 76: Pipeline river crossing

http://teeic.anl.gov/er/transmission/activities/act/index.cfm

Photo- 77: Pipeline river crossing

http://nessdp.blogspot.com/2010_10_01_archive.html

Article 83-2. Sheath tube

1. Sleeved crossings

   Sleeved crossings must be avoided where possible as shown in Fig-34 and Photo-78.

   Note: API RP 1102 provides guidance on the design of sleeved crossings.

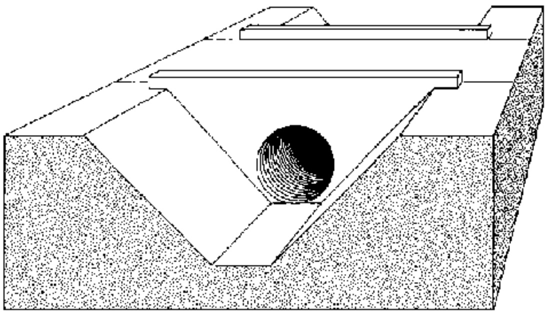


Fig- 34: Sheath tube for pipeline under the rosd

http://www.fao.org/docrep/R4082E/r4082e06.htm

Photo- 78: Sheath tube for pipeline under the rosd

http://www.truth-out.org/latest-bp-oil-spill-took-place-facility-employee-said-was-operating-unsafe-condition/1311082418

2. When installing pipeline in the sheath tube or other structure (hereinafter so called "sheath tube, etc."), it must be pursuant as follows;

(1) Piping and sheath pipe must be avoided contact by means of filling buffer between them.
(2) The ends of sheath pipe must be closed if there is building, bank and the like.

3. The use of casings for the crossing of roads or railways must be discharged because of the difficulty in providing the pipeline with adequate protection against external corrosion. When casings are stipulated by local authorities, the cathodic protection of the pipeline section within the casing must be carefully reviewed. Recommendations on pipeline crossings of roads and railways are contained in API RP1102. Directional drilling is particularly suitable for long crossings, e.g. rivers and waterways; the method can achieve large buried depths, and it is insensitive to current, river traffic, etc.
4. The recommended minimum covers at crossings are given in Table-15. A minimum vertical separation of 0.3m must be kept between the pipeline and any other buried structures, e.g. existing pipelines, cables, foundations, etc.

Article 83-3. Piping cover

1. Depth of ditch must be appropriate for the route location, surface use of the land, terrain features, and loads imposed by roadways and railroads. All buried pipelines must be installed below the normal level of cultivation and with a minimum cover not less than that shown in Table-15. Where the cover provisions of Table-15 cannot be met, pipe may be installed with less cover if additional protection is provided to withstand anticipated external loads and to minimize damage to the pipe by external forces.
2. Width and grade of ditch must provide for lowering of the pipe into the ditch to minimize damage to the coating and to facilitate fitting the pipe to the ditch.
3. Location of underground structures intersecting the ditch route must be determined in advance of construction activities to prevent damage to such structures. A minimum clearance of 12 in. (0.3 m) must be provided between the outside of any buried pipe or component and the extremity of any other underground structures, except for drainage tile which must have a minimum clearance of 2 in. (50 mm), and as permitted under para. 461.1.1(c).
4. Ditching operations must follow good pipeline practice and consideration of public safety. API RP 1102 will provide additional guidance.

Table- 15: Minimum cover for buried pipelines (ASME B31.4-2009)

Location	For normal excavation in. (m)	For rock excavation requiring blasting or removal by equivalent means in. (m)
Cultivated, agricultural areas where plowing or subsurface ripping is common	48 (1.2) [Note (1)]	N/A
Industrial, commercial and residential areas	48 (1.2)	30 (0.75)
River and stream crossings	48 (1.2)	18 (0.45)
Drainage ditches at roadways and railroads	48 (1.2)	30 (0.75)
All other areas	36 (0.9)	18 (0.45)

Note (1): Pipelines may require deeper burial to avoid damage from deep plowing; the designer is cautioned to account for this possibility.

Article 84. Measure for leakage and spread of oil pipeline, etc

Article 84-1. Measure for leakage

1. “The measure to prevent the spread of leaked hazardous leakage” must be pursuant to as follows;

(1) The structure to prevent the spread of dangerous material must be the steel plate with more than 1.6mm thickness and must have the width more than such road when it crossing the road and the like.

(2) The clearance between pipeline and the structure to prevent the spread of dangerous material must be avoided contact with said pipe and structure by a spacer.

(3) The structure must not penetrate rainwater; in addition, drain pipe must be provided in appropriate position and led to the oil separation tank if both ends are closed.

(4) The inspection opening must be provided to allow easy inspection of the situations of painting for pipe in such structures.

Article 85. Prevention of accumulation of flammable vapor from oil pipeline, etc.

Article 85-1. Flammable vapor

1. The check box and “device which is capable to detect flammable vapor” as shown in Fig-35 must be pursuant to as follows other than the standard for the measure of flange joint.

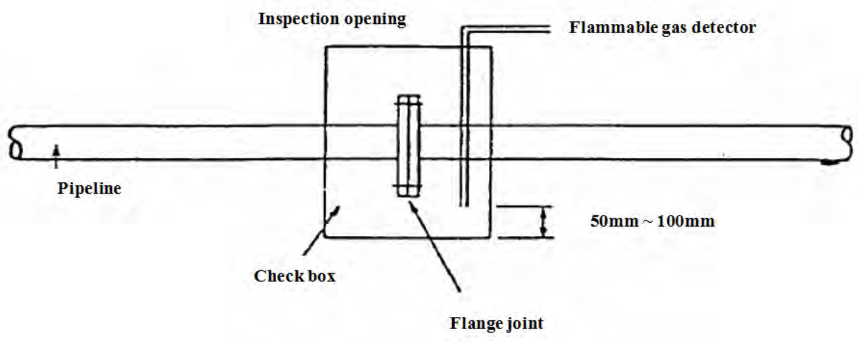


Fig- 35: Check box

Reference: Regulation for the transportation and handling station of hazardous materials (Dec. /2011):

Ministry of Internal Affairs and Communications Japan)

(1) The check box must be provided automatic sensing device where flammable vapors may scatter. However, check boxes which are installed in the place where flammable vapors may not scatter out of the premises may be the construction which can be detected by hand.

(2) The tip of automatic detection device sensor must be more than 5cm and less than 10cm from the bottom of the check box.

(3) The measuring nozzle must be provided to the check box with structure which can be detected by manual inspection.

Article 86. Installation in a place where there might be uneven settlement, etc.

Article 86-1. Uneven settlement

1. It is not avoidable to place oil pipeline depending on the location of oil wells, though is typically installed on the flat ground. The sufficient research in the location where landslides had occurred must be performed and must be avoided such places, since the damage and oil leakage accident due to landslides are still occurring. The submarine landslides must be considered in case of the submarine pipeline as well as the pipeline on the land.
2. In addition, there is possibility of leakage accident and cause damage by subsidence and uplift of the pipeline due to the liquefaction in case of installed in swamps, landfills and the like. The sufficient investigation must be performed in order to avoid unsuitable site when determining the route well and an appropriate measure must be taken if it is not unavoidable.

Article 87. Oil pipeline connection with bridge

Article 87-1. Connection with bridge

1. Pipe bridge crossings

   Pipeline bridges may be considered when buried crossings are not practicable as shown in Photo-80. Pipe bridges shall be designed in accordance with structural design standards, with sufficient clearance to avoid possible damage from the movement of traffic as shown on Photo-79, and with access for maintenance. Interference between the cathodic protection of the pipeline and the supporting bridge structure shall be considered. Provision shall be made to restrict public access to pipe bridges.

Photo- 79: Non-conductive pipe roller

http://www.glasmesh.com/GMPAGE1.htmL

Photo- 80: Piping bridge

http://www.bphod.com/2011/04/camellia-utility-bridge-over-parramatta.html

Article 88. Non destructive test of oil pipeline, etc.

1. All welds on the pipeline are generally subjected to inspection by radiography. This is achieved on the main pipeline by an internal X-ray tube travelling along the inside of the pipe carrying out X-rays at each weld for approximately 2 minutes per weld. On completion of X-ray the film is taken to a dark or early the next day. Welds, which do not meet the required acceptance criteria, are either repaired or cut out and re-welded. Experienced and qualified X-ray specialists undertook the radiography under controlled conditions. Before the operation is started, the section of pipeline is cordoned off by marker tape to stop entry by non X-ray personnel and audio/flashing warning alarms are activated during all times when the X-ray tube is energized. The X-ray personnel are on constant surveillance to ensure that the workforce and members of the public are aware of the X-ray acuities and only authorized access is permitted.

   Welds completed by semi-automatic welding processes are examined using automatic ultrasonic testing (AUT) techniques. This consists of an assembly that traverses the circumference of each completed weld in order to detect any defects. The results of each ultrasonically inspected weld are automatically recorded and are used to determine whether a weld repair is required and if so what type.

2. Welding examination

2.1 Welding standard

Welding of pipeline systems must be carried out in accordance with ISO 13847.

2.2 Weld examination

Examination of welds in pipeline systems must be performed in accordance with ISO 13847 and, except as allowed for tie-in welds in 11.5, the weld examination must be carried out before pressure-testing. The extent of the non-destructive examination for girth welds must be as follows:

(1) All welds must be visually examined.

(2) A minimum of 10 % of the welds completed each day must be randomly selected by the owner or owner's designated representative for examination by radiography or ultrasonic. The 10 % level must be used for pipelines in remote areas, pipelines operating at 20 % or less of SMYS, or pipelines transporting fluids which are low hazards to the environment or personnel in the event of a leak. The percentage of weld examination for other fluids and locations must be selected appropriate to the local conditions. The examination must be increased to 100 % of the welds if lack of weld quality is indicated, but may subsequently be reduced progressively to the prescribed minimum percentage if a consistent weld quality is demonstrated.

(3) 100 % of the welds must be examined by radiography or ultrasonic in the following circumstances:

1) pipelines designed to transport category C fluids at hoop stresses above 77 % of SMYS;
2) pipelines designed to transport category D fluids at hoop stresses at or above 50 % of SMYS;
3) pipelines designed to transport category E fluids;
4) pipelines not pressure-tested with water;
5) within populated areas such as residential areas, shopping centers, and designated commercial and industrial areas;
6) in environmentally sensitive areas;
7) river, lake, and stream crossings, including overhead crossings or crossings on bridges;
8) railway or public highway rights-of-way, including tunnels, bridges, and overhead crossings;
9) offshore and coastal waters;
10) tie-in welds not pressure-tested after installation.

(4) Radiography or ultrasonic examination must cover the weld over its full circumference. The examination must be appropriate to the joint configuration, wall thickness and pipe diameter.

(5) Welds must meet the acceptance criteria specified in the applicable welding standard. Welds not meeting these criteria must either be removed or, if permitted, repaired and reinspected. All other welds must be fully examined in accordance with ISO 13847.

Article 88-1. RT

1. Welded joint must be confirmed its soundness by non-destructive testing represented by RT immediate after welding as shown on Fig-36, Photo-81, 82 and 83. Especially, burring the pipeline must be performed after ensuring the soundness, completing repair welding and anti-corrosion treatment of welding joints.

Photo- 81: RT

http://www.cituk-online.com/acatalog/Oil_and_Gas_Pipeline.html

Photo- 82: RT

http://news.thomasnet.com/company_detail.html?cid=10029331&sa=10&prid=827307

Photo- 83: RT

http://mepts.com/about_us.html

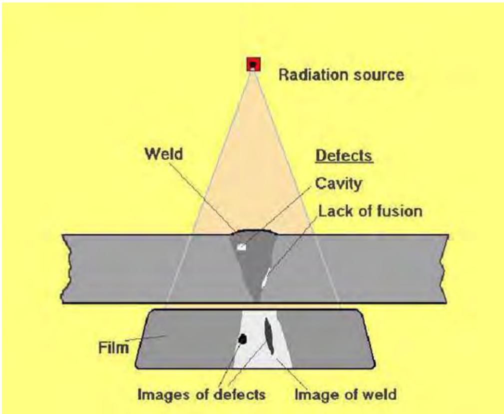


Fig- 36: RT

http://www.classle.net/book/testing-weld

Article 88-2. UT

1. UT as shown in Photo-84, 85 is the non-destructive testing methods to replace the RT.

Photo- 84: Auto-UT

http://www.directindustry.com/prod/olympus-industrial/ultrasonic-welding-inspection-devices-17434-482218.html

Photo- 85: UT

http://www.virtualengg.com/ultrasonic.html

Article 89. Pressure test of oil pipeline, etc.

Article 89-1. Pressure test

1. General

   Pipeline systems must be pressure-tested in place after installation but before being put into operation to demonstrate their strength and leak-tightness. Prefabricated assemblies and tie-in sections may be pretested before installation provided their integrity is not impaired during subsequent construction or installation. The requirements for pressure testing can govern the necessary pipe wall thickness and/or steel grade in terrain with significant elevations.

2. Test medium

   Test medium available, when disposal of water is not possible, when testing is not expedient or when water contamination is unacceptable. Pneumatic tests (when necessary) may be made using air or a non-toxic gas as shown in Photo-86, 87.

Photo- 86: Compressor for pressure test

http://www.atlascopco.us/hurricane/applications/pipeline/

Photo- 87: Compressor for pressure test

http://www.aabbxair.com/about.html

3. Pressure test requirements

   Pressure tests shall be conducted with water (including inhibited water), except when low ambient temperatures prevent testing with water, when sufficient water of adequate quality cannot be made.

   NOTE Rerouting of short pipeline sections or short tie-in sections for pipelines in operation are examples of situations for which pressure tests with water may not be expedient.

4. Pressure levels and test durations

   The pipeline system must be strength-tested, after stabilization of temperatures and surges from pressurizing operations, for a minimum period of 1h with a pressure at any point in the system of at least:

   1) 1.25 × MAOP for pipelines on land; and
   2) 1.25 × MAOP minus the external hydrostatic pressure for offshore pipelines.

If applicable, the strength test pressure must be multiplied by the following ratios:

1) the ratio of σ_y at test temperature divided by the derated value for σ_y at the design temperature in case of a lower specified minimum yield strength σ_y at the design temperature than exists during testing; and
2) the ratio of t_{min} plus corrosion allowance divided by t_{min} in case of corrosion allowance.

The strength test pressure for pipelines conveying category C and D fluids at locations subject to infrequent human activity and without permanent habitation may be reduced to a pressure of not less than 1.20 times MAOP, provided the maximum incidental pressure cannot exceed 1.05 times MAOP.

Following a successful strength test, the pipeline system shall be leak-tested for a minimum period of 8h with a pressure at any point in the system of at least:

1) 1.1 × MAOP for pipelines on land; and
2) 1.1 × MAOP minus the external hydrostatic pressure for offshore pipelines.

The strength and leak test may be combined by testing for 8 h at the pressure specified above for strength testing. The requirement for a minimum duration of a leak test is not applicable to pipeline systems completely accessible for visual inspection, provided the complete pipeline is visually inspected for leaks following a hold-period of 2h at the required leak-test pressure. The additional test requirements of clause B.6 must apply for category D and E pipelines to which Annex-B of ISO 13623-2000 applies.

5. Acceptance criteria

Pressure variations during strength testing must be acceptable if they can be demonstrated to be caused by factors other than a leak. Pressure increases or decreases during leak testing must be acceptable provided they can be demonstrated through calculations to be caused by variations in ambient temperature or pressure, such as tidal variation for offshore pipelines. Pipelines not meeting these requirements must be repaired and retested in accordance with the requirements of this International Standard.

Article 90. Operation monitoring device for oil pipeline, etc.

Article 90-1. Monitoring equipment

1. See Article 62-1.

Typical arrangement of monitoring CRT is shown in Photo-88 and 89.

Photo- 88: Central monitoring board

http://www.shibushi.co.jp/safety/index.html

Photo- 89: Central monitoring board

http://www.lundhalsey.com/oil_gas.htm

Article 90-2. Warning equipment

1. See Article 62-1.

   Typical arrangement of warning board is shown in Photo-90 and 91.

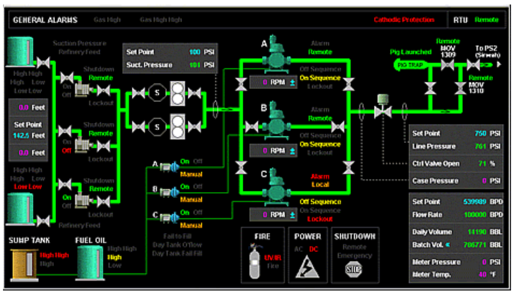


Photo- 90: System flow on monitoring board

http://www.lee-dickens.biz/systems/app_oil.htm

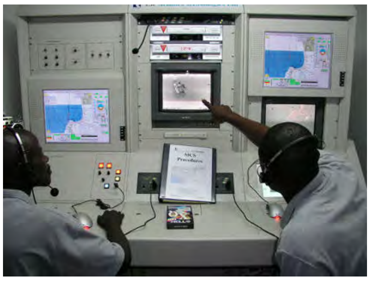


Photo- 91: Pipeline monitoring

http://www.barnardmicrosystems.com/L3_oil_pipeline.htm

Article 91. Safety controller for oil pipeline, etc

Article 91-1. Safety controller

1. The reliable network is required for the pipeline monitoring system in order to monitor the pressure and flow conditions of pipeline 24hours continuously and to establish an efficient communication with the central SCADA system. The pipeline monitoring system is required the extensive network to connect field devices by the fiber optic cable installed in parallel with pipeline in order to monitor corrosion and failures by third parties in real time detect as well as latent leaks and temperature anomalies.

   1) Extensive real time data collection
   2) Wireless connection
   3) High bandwidth for real time video data monitoring in the long distance

4) Industrial grade device that supports wide operating temperature and meets the safety regulation compatible for use in hazardous environments in order to build a very robust monitoring network

Article 92. Pressure relief device for oil pipeline, etc

Article 92-1. Pressure relief device

1. Surge Control and Relief Systems as shown in Fig-37, Photo-92 are widely used in many applications such as major oil & petrochemicals pipelines, marine terminals, tank farms etc. Generally all systems where pressure contained require some kind of pressure relief. Dispensing this rule endangers both your personnel and equipment and often leads to serious damage of valuable assets. Surge pressure is a consequence of a sudden change of fluid velocity that can be caused by

   1) Rapid valve closure;
   2) Pump Start;
   3) Up and emergency Shut Down.

   Long pipelines can produce dangerous pressures that result in:

   1) Flanged connections detachments;
   2) Fatigue pipe breakdown;
   3) Welding seam integrity damage;
   4) Cracks inside pipe body;
   5) Misalignment of pump outlet and discharge pipeline;
   6) Various piping components (tees, strainers, loading arms etc.) damage.

Photo- 92: Pressure relief

http://www.equityeng.com/consulting-services/pressure-relieving-systems/pipeline-relief-device-integrity

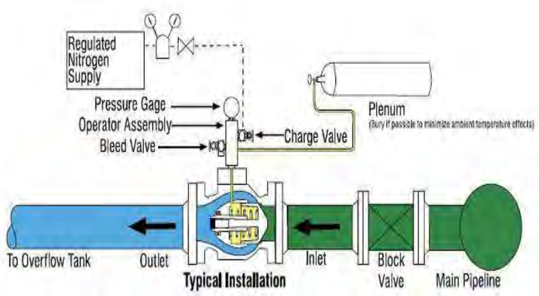


Fig- 37: Pipeline surge protection

http://baharsanat.com/?lng=en&cid=cms&gid=294&content=185

Article 92-2. Strength of pressure relief device

1. Compatibility with the process fluid is achieved by careful selection of materials of construction. Materials must be chosen with sufficient strength to withstand the pressure and temperature of the system fluid. Materials must also resist chemical attack by the fluid and the local environment to ensure valve function is not impaired over long periods of exposure. The ability to achieve a fine finish on the seating surface of disc and nozzle is required for tight shut off. Rates of expansion caused by temperature of matching parts are another design factor.
2. Most pipeline codes, do not stipulate any requirement for block valve spacing nor for remote pipeline valve operations along transmission pipelines carrying low vapor pressure petroleum products. This requirement is generally industry driven for their desire to proactively control hazards and mitigation of environmental impacts in the event of pipeline ruptures or failures causing hydrocarbon spills. This paper will highlight a summary of pipeline codes for valve spacing requirements and spill limitation in high consequence areas along with criteria for an acceptable spill volume that could be caused by pipeline leak/full rupture. A technique for deciding economically and technically effective pipeline block valve automation for remote operation to reduce oil spill and thus control of hazards is also provided. The criteria for maximum permissible oil spill volume, is based on industry's best practice. The application of the technique for deciding valve automation as applied to three initially selected pipelines (ORSUB, OSPAR and ORBEL) is discussed. These pipelines represent about 14% of the total (6,800 kilometers, varying between 6” to 42”) liquid petroleum transmission lines operated by Petobras Transporte S.A. (Transpetro) in Brazil. Results of the application of the technique is provided for two of the pipelines: OSPAR (117 Km, 30” line) and ORBEL II (358 Km 24” line), both carrying large volumes of crude oil.

Reference: ASME Digital Library Paper No. IPC2004-oo22 pp. 2133-2138

Article 92-3. Capacity of pressure relief device

1. The following formulae extracted from API Recommended Practice 520 are provided to enable the selection of effective discharge areas. The effective discharge areas will be less than the actual discharge areas, therefore these formulae must not be used for calculating certified discharge capacities. After determining the required effective area selected from Table-16 the orifice with an area equal to or greater than the required effective discharge area.

$$A = \frac{0.621 \times W}{K_d \times K_w \times K_v \times \sqrt{(P_1 - P_2) \times q}}$$

Where

		(Metric units)
A	: required effective discharge area of the valve	mm^2
$\boldsymbol{P_1}$	**: relieving pressure: for liquids (=set pressure+allowable overpressure)**	**bar**
P_2	: back pressure	bar
W	: flow rate	kg/h
q	: density of a liquid	Kg/m^3
K_d	: effective coefficient of discharge related to the effective flow areas acc. To API 526; for liquids (=0.685)	—
K_v	: correction factor due to viscosity; for Reynolds number > 60000 (=1.0)	—
K_w	: capacity correction factor due to back pressure (for balanced bellows valves and liquid only); with back pressure < 15% P_1 (=1.0)	—

Table- 16: Effective areas acc. to API 526

Orifice	Effective areas (mm^2)
D	71
E	126
F	198
G	324
H	506
J	830
K	1,185
L	1,840
M	2,322
N	2,800
P	4,116
Q	7,129
R	10,322
T	16,774

Article 93. Leakage detector, etc. for oil pipeline, etc.

Article 93-1. Leakage detector

1. Oil leak detector as shown in Fig-38 and Photo-93 is a liquid hydrocarbon leak detection system consisting of a conductive silicone rubber swelling sensors and dedicated detectors. Sensor is flexible and detects reliably by the touch of a portion of the long oil leakage sensor in very small quantity. Applications will be utilized for leak detection equipment for oil storage facility, oil refinery, oil pipeline, underground storage facility and chemical facility. This has the following features;

    1) Good weathering, easy installation, maintenance-free because of rubber belt type sensor
    2) It can be used in oil storage base for intrinsically safe construction.

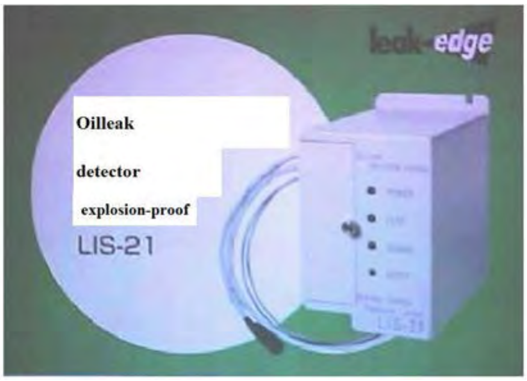


Photo- 93: Oil leak detector

http://www.yagishita-e.co.jp/jigyoubu/denshi/denshi-03.htm

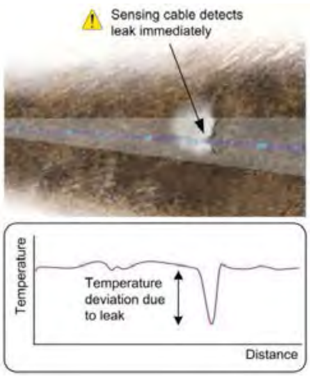


Fig- 38: Digital pipeline leak detection

http://www.sensornet.co.uk/products-services/downstream-home/digital-pipeline-leak-detection/

Article 94. Emergency shut-off valve for oil pipeline, etc.

Article 94-1. Emergency shut-off valve

1. ESD valves must be located at each end of the pipeline, and on the incoming and outgoing sections at any plant of route, such as the pumping stations. The valves must be located in a non-hazardous area, e.g. close to the plant fences.
2. An ESD valve must be located at the top of each riser connected to an offshore platform. It must be placed below the platform lower deck level for protection against topsides incidents. For pipelines connected to manned offshore complexes, and in addition to the top of riser ESD valve, a subsea ESD valve located on seabed close to the platform may be considered. Subsea valves must be justified by a quantitative risk assessment. The distance of the subsea ESD valve from the platform must be delivered such that the combined risk associated with the platform activities and the pipeline fluid inventory between the valve and the platform is minimized.
3. ESD valves must not incorporate bypass arrangements. Pressure balancing, if required prior to valve opening, must be done using the operational valves located immediately upstream or downstream of the ESD valve.

Article 94-2. Function of shut-off valve

1. Three methods of operating block valves can be considered: locally, remotely and automatically. The appropriate method must be determined from a study of the likely effects of a leak and acceptable released volumes, based on the total time in which a leak can be detested, located and isolated. The closure time of the valves must not create unacceptably high surge pressures. Automatic valves can be activated by detection of low pressure, increased flow, rate of loss of pressure or a combination of these, or a signal from a leak detection system. Low pressure detection must not be used if the control system is designed to maintain the pipeline pressure. Automatic valves must be fail-safe.
2. For pipelines transporting B, C and D fluid, the isolation of remotely operated sectionalizing block valves is recommended to further reduce the extent of a leak. The emergency shutdown valves must be automatically actuated when an emergency shutdown condition occurs at the plant or facility.

Article 94-3. Indication of open and close

1. See Article62-3 “Indication of valve opening status”.

Article 94-4. Installation in the box

1. If it cannot provide emergency shutoff valve, section valve, block valves and the like for buried pipeline on the ground, they must be installed in the pit as shown in Photo-94 taking into account the need for a check and replacement. The Photo-95 is the stem extension valve for underground pipeline.

Photo- 94: Underground valve pit

http://www.sltrib.com/sltrib/home/50792448-76/oil-chevron-butte-red.html.csp

Photo- 95: Stem extension valve for underground pipeline

http://www.tradekey.com/product_view/id/639836.htm

Article 94.5. Specified person

1. Each operator must have and follow a written qualification program. The program must include provisions to:

1) Identify covered tasks;

2) Ensure through evaluation that individuals performing covered tasks are qualified;

3) Allow individuals that are not qualified pursuant to this subpart to perform a covered task if directed and observed by an individual that is qualified;

4) Evaluate an individual if the operator has reason to believe that the individual's performance of a covered task contributed to an accident as defined;

5) Evaluate an individual if the operator has reason to believe that the individual is no longer qualified to perform a covered task;

6) Communicate changes that affect covered tasks to individuals performing those covered tasks;

7) Identify those covered tasks and the intervals at which evaluation of the individual's qualifications is needed;

2. Pipeline operator qualification by US Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA).

To assure safety in the transport of hazardous gases and liquids in the nation's pipelines, pipeline operators who perform covered tasks must be qualified. Qualified means that an individual has been evaluated and can perform assigned covered tasks and recognize and react to abnormal operating conditions.

Article 95. Oil removal measure for oil pipeline, etc.

Article 95-1. Removal of oil

1. Draining

Liquids may be pumped, or pigged, out of a pipeline using water or an inert gas. Hazards and constraints which must be considered when planning to drain include:

1) asphyxiating effects of inert gases;
2) protection of reception facilities from over-pressurization;
3) drainage of valve cavities, “dead legs”, etc.;
4) disposal of pipeline fluids and contaminated water;
5) buoyancy effects if gas is used to displace liquids;
6) compression effects leading to ignition of fluid vapor;
7) combustibility of fluids at increased pressures;
8) accidental launch of stuck pigs by stored energy when driven by inert gas.

2. Purging

Hazards and constraints which must be considered when preparing for purging include:

1) asphyxiating effects of purge gases;
2) minimizing the volume of flammable or toxic fluids released to the environment;
3) combustion, product contamination or corrosive conditions when reintroducing fluids.

Article 96. Seismic sensor, etc. for oil pipeline, etc.

Article 96-1. Seismic sensors

1. See Article 62-6 “Seismic sensor”.

Article 97. Notification facility of oil pipeline, etc

Article 97-1. Report facility

1. For any pipeline system, telecommunications must be provided to assist the operational and maintenance activities (pipeline inspection, end to end communications for pigging operations, emergency situations, etc.). Pipeline monitoring from a central location and remote operations involving the use of telecommunications must be considered for all pipelines transporting toxic fluids.

Article 97-2. Emergency reporting facility

1. See Article 62-10.

Article 97-3. Location of reporting facility

1. See Article 62-10.

Article 98. Alarm facility of oil pipeline, etc.

Article 98-1. Warning facility

1. See Article 106-1.

Article 99. Firefighting facility for oil pipeline, etc.

Article 99-1. Fire extinguishing equipment

1. The appropriate fire extinguishing equipment such as gas, bubble, water and the like must be provided in the place where equipments such as the receiving facility, the metering facility, pump station, storage tank and the like are concentrated as shown in Photo-96, 97.

Photo- 96: Fire extinguishing

http://www.kockw.com/pages/Media%20Center/What's%20 New/NewsDetails.aspx?ID=23

Photo- 97: Fire-fighting drill

http://www.sciencephoto.com/media/153267/enlarge

Article 100. Chemical fire engine for oil pipeline, etc.

Article 100-1. Chemical fire engine

1. It is not realistic to install water or bubble fire extinguishing pipeline along with the long distance pipeline and the water tank vehicle, the concentrated form vehicle and the high water cannon as shown in Photo-98, 99 must be provided and responded with flexibility.

Photo- 98: Chemical engine

http://wwwcms.pref.fukushima.jp/pcp_portal/PortalServlet;jsessionid=3F5A58EE5AE65C2FB36FB787F9BD163E?DISPLAY_ID=DIRECT&NEXT_DISPLAY_ID=U000004&CONTENTS_ID=11342

Photo- 99: Spraying of chemicals

http://rei.da-te.jp/c4454_2.html

Article 101. Back-up power for oil pipeline, etc.

Article 101-1. Reserve power source

1. As a measure in case of main electric power outage, the emergency electric power, emergency electric generator required to stop facilities safely and the uninterruptible power supply unit required to perform monitoring, alarm and notification until a steady state must be provided as for the back-up power supply facility as shown in Pfoto-100, 101.

Photo- 100: Emergency diesel generator

http://www.yamabiko-corp.co.jp/shindaiwa-japan/?p=4553

Photo- 101: Uninterruptible power supply

http://www.oce.co.jp/12greenit/02-9-5ups-backup.html

Article 102. Grounding, etc. for safety of oil pipeline, etc

Article 102-1. Grounding system

1. Filling stations

   At filling stations for cars, railways, ships... with hazardous areas defined as zones 2 and 22, all the metal pipelines should be carefully earthed. They should be connected with steel constructions and rails, if necessary via isolating spark gaps approved for the hazardous zone in which they are installed, to take into account railway currents, stray currents, electrical train fuses, cathodic-corrosion-protected systems and the like.

2. Storage tanks

   Certain types of structures used for the storage of liquids that can produce flammable vapors or used to store flammable gases are essentially self-protecting, i.e. contained totally within continuous metallic containers having a thickness of not less than 4 mm of steel (or equivalent for other metals: 5 mm of copper or 7 mm of aluminum), with no spark gaps and require no additional protection. Similarly, soil-covered tanks and pipelines do not require the installation of air-termination devices. Nevertheless, instrumentation and electric devices used inside this equipment should be approved for this service. Measures for lightning protection should be taken according to the type of construction. Isolated tanks or containers should be carefully earthed at least every 20 meters.

3. Floating roof (storage) tanks

   In the case of floating roof tanks, the floating roof should be effectively bonded to the main tank shell. The design of the seals and shunts and their relative locations need to be carefully considered so that the risk of any ignition of a possible exposure mixture by incendiary sparking is reduced to the lowest level practicable. When a rolling ladder is fitted, a flexible bonding conductor of 35 mm width should be applied across the ladder hinges, between the ladder and the top of the tank and between the ladder and the floating roof. When a rolling ladder is not fitted to the floating roof tank, several flexible bonding conductors of 35 mm width (or equivalent) shall be applied between the tank shell and the floating roof. The bonding conductor should either follow the roof drain or be arranged so that they cannot form re-entrant loops. On floating roof tanks, multiple shunt connections should be provided between the floating roof and the tank shell at about 1.5 m intervals around the roof periphery. Alternative means of providing an adequate conductive connection between the floating roof and tank shell for impulse currents associated with lightning discharges are only allowed if proved by tests and if procedures are utilized to ensure the reliability of the connection.

4. Pipelines

Overground metal pipelines outside the production facilities should be connected every 30 m to the earthling system. For the transport of flammable liquids, the following applies for long distance lines:

1) in pumping sections, sliding sections and similar facilities, all lead-in piping including the metal sheath pipes should be bridged by conductors with a cross-section of at least 50 mm^2;
2) the bridging conductors should be connected with especially welded-on lugs or by screws which are selfloosening, secure to the flanges of the lead-in pipes; insulated pieces should be bridged by spark gaps.

For a pipeline station as shown in Fig-39, lightning protection requires multipole SPDs on the supply in the low-voltage distribution systems, for telecommunication and telecontrol, for intrinsically safe circuits (made of stainless steel for outdoor areas) and explosion-protected ATEX spark gaps in Ex-zones 1 and 2.

5. Cathodic protection systems

Cathodic protection (CP) systems are generally protected (against surges and lightning currents) by using explosion protected ATEX spark gaps in Ex-zones 2. Cables going out of the CP rectifier (measuring cables and anode electrical circuits) are led via SPDs especially adjusted to such installations, so that the partial lightning currents coming from the pipeline as well as surges caused by switching operations can be safely controlled. It is recommended to install the SPDs into a corresponding separate steel enclosure in order to prevent any threat to the CP installation due to overloads (for example, via overhead lines).

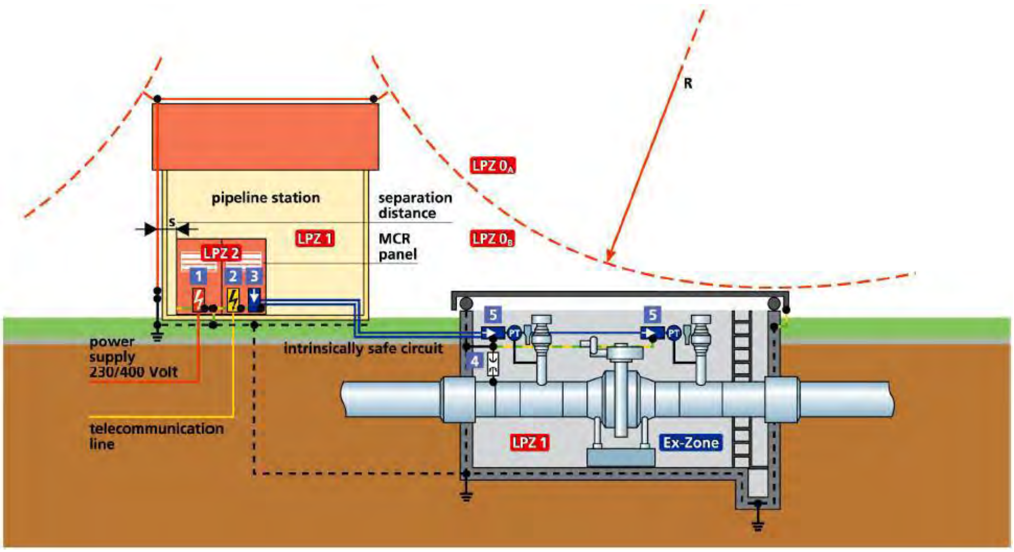


Fig- 39: Lightning and surge protection for a pipeline station

http://ws9.iee.usp.br/sipdax/papersix/sessao12/12.9.pdf

Article 103. Isolation of oil pipeline, etc.

Article 103-1. Isolation of pipeline

1. The pipeline must be isolated from other structure such as supports, if there is a need for security.

Article 103-2. Insert for isolation

1. An insulating coupling must be used for the pipeline, if there is a need for security.

Article 103-3. Arrester

1. When installing the pipe close to the grounding locations of the arrester, measures for the insulation must be taken as shown in Fig-40.

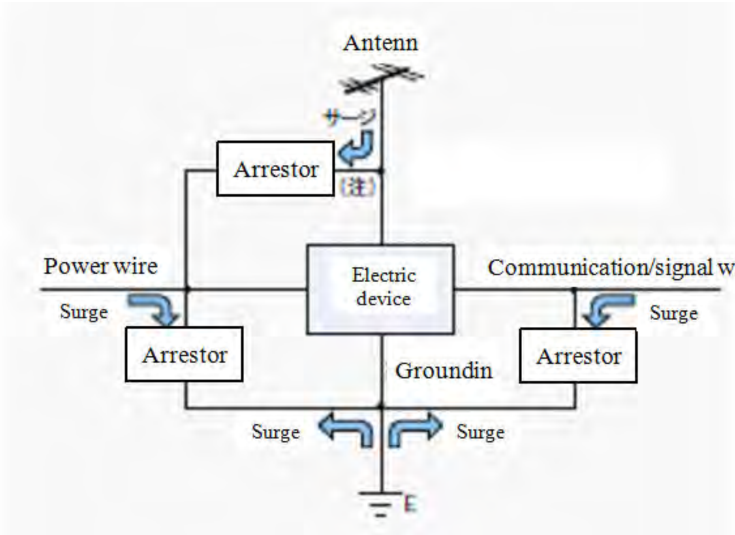


Fig- 40: Arrester

http://www.fujielectric.co.jp/technica/tecnews/2000au/2.pdf

Article 104. Lightning protection system for oil pipeline, etc.

Article 104-1. Lightning protection

1. The lightning protection equipment must be installed, if it is necessary for the security of commercial facilities.
2. Conditions Ground potential rise (GPR), describes those conditions produced in the earth's surface where abnormally elevated voltage charges result from downed power line phase conductors that come into contact with soil. A lightning ground strike also produces, for the same instant in time, a GPR condition. As the GPR voltage encounters grounded metallic objects, charges are transferred into them and fault currents will flow through all interconnecting conducting mediums during the dissipation of the energy. For example, a cathodic protection system ground rod is connected via the AC Power connection neutral to the very well grounded power Sub Station as shown in Fig-41. A potential difference will exist between the two upon a Lightning strike at or near the site. As the potential difference or imbalance that exists between these two ground sources equalizes, the resulting fault current flow can and often will damage sensitive circuits in the path

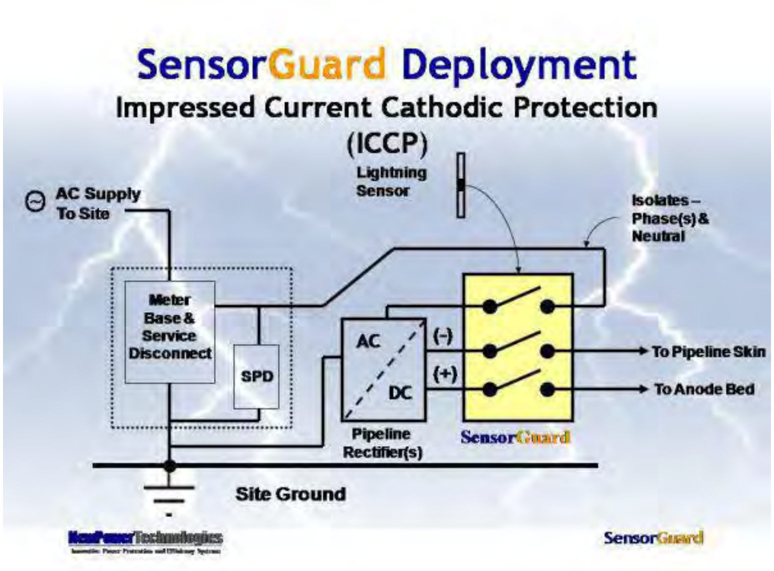


Fig- 41: Impressed current cathodic protection

http://home.btconnect.com/genasys/genasys_sensorguard_pipeline.htm

Article 105. Indication, etc. for oil pipeline, etc.

Article 105-1. Location mark

1. The buried pipeline must be prevented from accidents caused by excavation damage by means of installing the display piles as shown in Fig-42, 43. The pipeline above ground must be indicated that it is transporting dangerous goods and the contacts must be displayed in the event of destruction, leakage and the like.

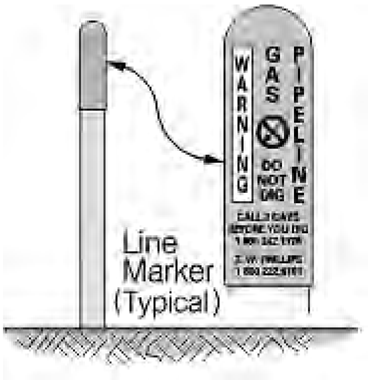


Fig- 42: Display pile for buried pipeline

http://www.twphillips.com/pipeline/Excavate.aspx

Fig- 43: Warning board for pipeline

http://www.cycla.com/opsiswc/wc.dll?webprj~ProjectHome ~&prj=0002

Article 106. Operation test of safety facility for oil pipeline, etc.

Article 106-1. Safety equipment

1. In the United States, the Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) published a final rule: "Pipeline Safety: Control Room Management/Human Factors." The final 49 CFR Part 192 and Part 195 rule amends the Federal pipeline safety regulations to address human factors and other aspects of control room management for certain pipelines where controllers use supervisory control and data acquisition (SCADA) systems – and seeks to reduce risk and improve safety during the transportation of hazardous gases and liquids. This ruling sets forth improvements to control room management that have value in the United States, where mandated, and around the world as good business practices.

Article 107. Pig handling equipment for oil pipeline, etc.

Article 107-1. Pig handling equipment

1. Design for pigging

   The requirements for pigging must be identified and the pipeline designed accordingly. Pipelines must be designed to accommodate internal inspection tools. The design for pigging must consider the following:

   1) provision and location of permanent pig traps or connections for temporary pig traps;
   2) access;
   3) lifting facilities;
   4) isolation requirements for pig launching and receiving;
   5) requirements for venting and draining (for pre-commissioning and during operation);
   6) pigging direction(s);
   7) permissible minimum bend radius;
   8) distance between bends and fittings;
   9) maximum permissible changes in diameter;

10) tapering requirements at internal diameter changes;

11) design of branch connections and compatibility of line pipe material;

12) internal fittings;

13) internal coatings;

14) pig signallers.

The safety of access routes and adjacent facilities must be considered when determining the orientation of pig traps.

2. Pig traps

All anticipated pigging operations, including possible internal inspection, must be considered when determining the dimensions of the pig trap. Pig traps, both permanent and temporary, must be designed with a hoop stress design factor in accordance with Table-1 and 2, including such details as vent, drain and kicker branches, nozzle reinforcements, saddle supports. Closures must comply with ASME Section VIII, Division 1. Closures must be designed such that they cannot be opened while the pig trap is pressurized. This may include an interlock arrangement with the main pipeline valves. Pig traps must be pressure-tested in accordance with 6.7.

3. Slug catchers

(1) Vessel-type slug catchers

All vessel-type slug catchers as shown in Photo-102, 103, wherever they are located, shall be designed and fabricated in accordance with ASME Section VIII, Division 1.

(2) Multi-pipe slug catchers

Multi-pipe slug catchers must be designed with a hoop stress design factor in accordance with Table-1 and 2.

Photo- 102: Cleaning pig

http://www.pigtek.com/

Photo- 103: Pig lunchaer reciever

http://pipelinepiglauncherreceiver.com/

Article 108. General provision of oil storage facility

1. The followings must be considered in case of the fuel oil storage base.

(1) "Protection dike" : The protection dike with a capacity of more than 110% of tank capacity for each group must be provided in order to prevent the spill of fuel oil leaked.

(2) "Oil spill prevention dike" : The oil dike for oil fuel tank of 10,000ℓ or more must be enclosed and must have capacity with greater than equal to the capacity of dike. In conjunction with a dike, it must be double enclosures.

(3) "Form extinguishing system" : The fire extinguishing equipment to covet the flame of oil surface, choke off the air and cool must be provided by means of generated from form maker of form fire extinguishing system which is fixed to the tank, if a fire occurs.

(4) "Watering and cooling equipment: The water curtain ring must be provided at the top of the roof and objective tank or adjacent tank must be cooled or protected by water curtain or water droplet-shaped particles.

2. "Monitoring device" : The flammable gas detector, oil leakage detector, surveillance camera must be provided in the central control room and be monitored remotely at all times.

Article 109. Oil storage tank

Article 109-1. Outdoor oil storage tank

1. Fixed roof type tank

   This is the most common type which is constructed as the liquid storage tank. They are divided into the conical roof tank (cone roof type) and the spherical shape roof tank (dome roof) depending on the type of roof as shown in Fig-44, 45 and Photo-104, 106. The conical roof tank is used for storage of less volatile liquid, since they are limited to low pressure at room temperature. The spherical shape tank is used for relatively highly volatile liquid; since they can be withstand pressure up to about several tens of kPa. The horizontal tank is applied to small amount storage tank as shown in Photo-105.

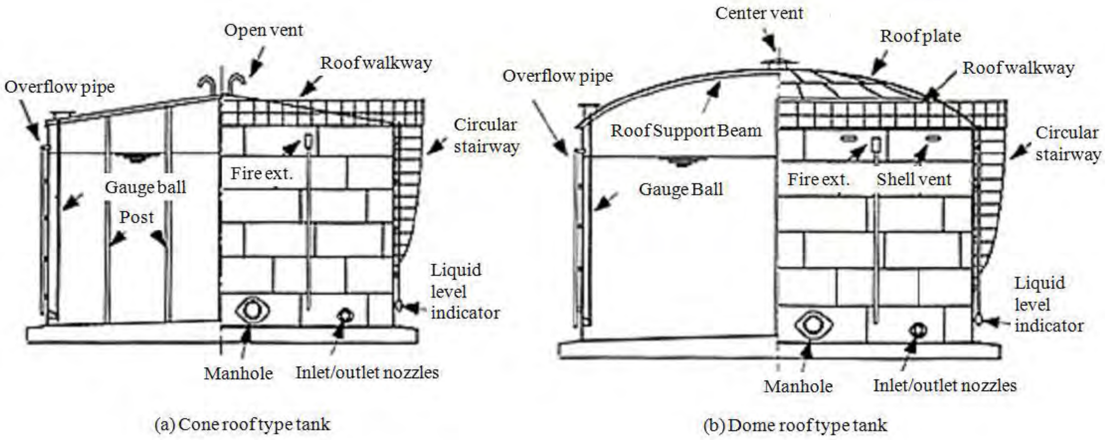


Fig- 44: Construction of fixed roof outdoor oil storage tank

http://www.jsim.or.jp/03_02_05.html

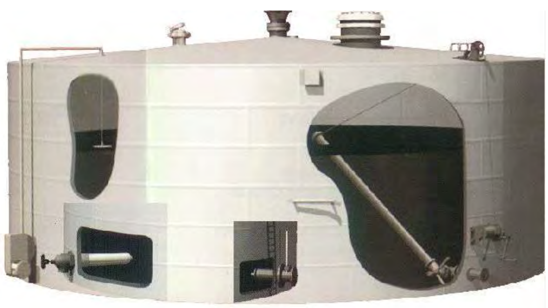


Fig- 45: Outdoor oil storage tank

http://i00.i.aliimg.com/photo/v0/259524222/Welded_Steel_Oil_Storage_Tanks.jpg

Photo- 104: Outdoor oil storage tank

http://upload.wikimedia.org/wikipedia/commons/d/d0/Oil_Storage_Tanks_-_geograph.org.uk_-_4843.jpg

Photo- 105: Outdoor oil storage tank

http://ghostdepot.com/rg/images/marshall%20route/salida%20oil%20storage%20tank%202001%20tlh%20P7250058.jpg

Photo- 106: Outdoor oil storage tank

http://www.dt-paint.com/english/product_ad1.asp

Article 109-2. Specific outdoor oil storage tank

1. Floating roof type tank

   This is one of the tanks for refineries and oil depot and has been adopted for a large liquid storage tanks as shown in Fig-46, 47 and Photo-107, 108 and 109. The roof is floated on the surface of stocked solution, contacts with the liquid portion of and moves up and down with in and out of liquid. Generally, there is no space to exist volatile organic compounds (VOC) caused by evaporation of oil and is suppressed VOC emission, since this type of tank has no space between the liquid surface and the roof. Also, the typical form of the floating roof is as follows;

(1) Floating roof type tank with single roof construction (single deck type)

   The center of the floating roof is single layer (single deck) and the ring shaped pontoon is provided around it.

(2) Floating roof type tank with double roofs construction (double deck type)

   This is the tank with double roofs, with less sinking of the roof, with excellent heat insulation and less leakage of VOC.

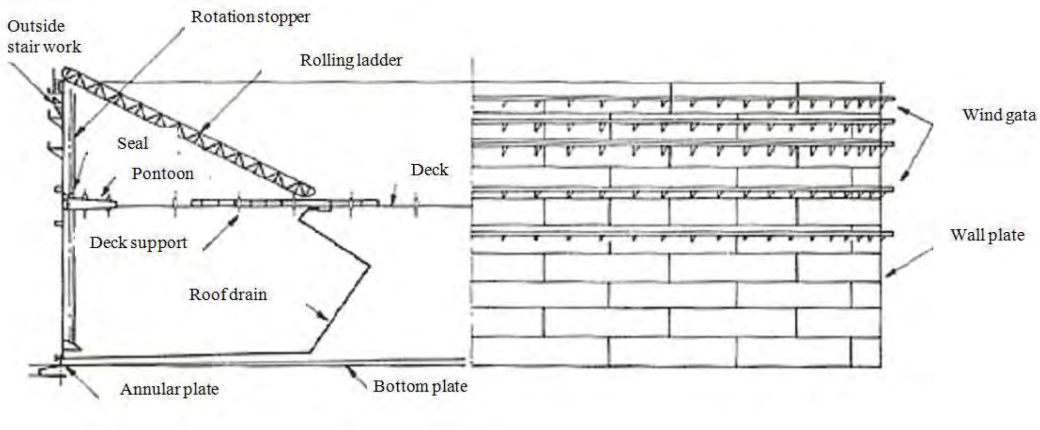


Fig- 46: Construction of floating roof type specific oil storage tank

http://www.jsim.or.jp/03_02_05.html

Photo- 107: Specific oil storage tank

http://www.watertubeboiler.org/oil-tanks-2/

Photo- 108: Specific oil storage tank

http://us.123rf.com/400wm/400/400/36clicks/36clicks0802/36clicks080200040/2546961-oil-storage-tanks-in-the-evening-light.jpg

Photo- 109: Crude oil tank

http://firma-vsc.de/js_index.php?pgid=PG_TANK01&lang=EN

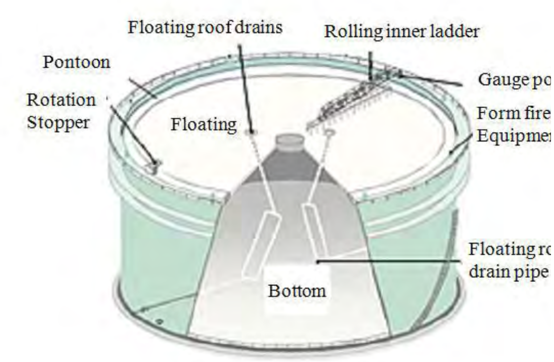


Fig- 47: Construction of floating roof tank

http://www.fdma.go.jp/html/hakusho/h16/h16/html/16133k20.html

Article 109-3. Underground oil storage tank

1. The underground oil storage tank as shown in Photo-110, 111 is applied to small output, emergency power generation facility, installation in downtown.

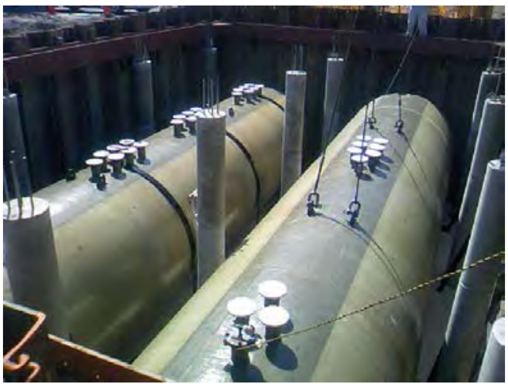


Photo- 110: Underground oil storage tank

http://y-ss.net/blog/?p=65

Photo- 111: Underground oil storage tank

http://naganoseiki.co.jp/newpage2.html

Article 109-4. Indoor oil storage tank

1. The indoor oil storage tank is applied to indoor fuel storage such as small output, emergency power generation facility and power plant in the downtown as shown in Photo-112, 113 and 114. In case of regular power generation facility, underground or above ground that has greater capacity than dispensing tank is necessary as shown in Photo-115.

Photo- 112: Indoor oil storage house

http://www.yusetsu.jp/okutan.htm

Photo- 113: Indoor oil storage tank

http://www.yusetsu.jp/okutan.htm

Photo- 114: Indoor oil storage tank

http://ehs.columbia.edu/OilStorageHadling.html

Photo- 115: Fuel dispensing tank

http://www3.ocn.ne.jp/~iss/hatsudenki_secchikouji.html

Article 109-5. Calculation of tank capacity

1. Cylindrical Tank With Flat Ends

   Whether the cylinder is vertical or horizontal, the formula is the same. To calculate the volume (V), measure the diameter (D) and length (L) of the cylinder. The formula is (3.14) × (D/2) ^2 × (L) = (V) cubic feet. Convert cubic feet to gallons by multiplying by the factor 7.48 gallons per cubic foot.

2. Cylindrical Tank With Round Ends

   If the tank is cylindrical in the middle with rounded ends, there is one additional step in the calculations. To calculate the volume (V), measure the length (L) and the diameter (D) of the cylinder and the radius of the half-sphere on one end (R). The formula is [(3.14) × (D/2) ^2 × (L)] + [(4/3) × (3.14) × (R) ^3] = (V) cubic feet. To convert cubic feet to gallons, multiply by 7.48 gallons per cubic foot.

3. Square Tanks

To calculate the volume (V) of a square or rectangular tank, measure the height (H), length (L) and width (W) of the tank. The formula is (H) × (L) × (W) = (V) cubic feet. To convert cubic feet to gallons, multiply by 7.48 gallons per cubic foot

Article 110.Pipeline of oil storage tank

1. The oil storage tank and piping around the tank must be placed orderly with consideration of the workability of operator, the operation of fire trucks and the like as shown in Photo-116, 117.

Photo- 116: Piping around oil tank

http://www.chemicals-technology.com/projects/neste-oil-plant/neste-oil-plant7.html

Photo- 117: Piping around oil tank

http://www.visualphotos.com/image/1x8518165/pipes_and_valves_with_oil_storage_tanks

Article 111. Changeover valve, etc. of oil storage tank

1. In petroleum storage facility, it may be to equalize the use or storage of each storage tanks, or give priority to specific withdrawal from the tank, in some cases make blending. In such cases, the switching valve such as ball valve as shown in Fig-48 and Photo-118 is used in order to perform reliable flow control.

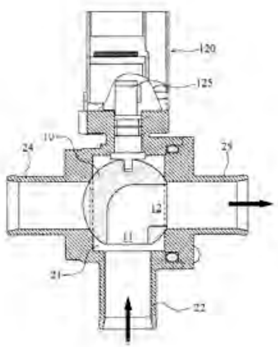


Fig- 48: Switching ball valve

http://patent.astamuse.com/ja/published/JP/No/2007132470/%E8%A9%B3%E7%B4%B0

Photo- 118: Switching ball valve

http://www.hydrocarbons-technology.com/contractors/valves/rotork-actuators/rotork-actuators5.html

Article 112. Oil receiving opening of oil storage tank

1. The oil pit which has 0.15m height dam, concrete ground and drain pit must be provided just below the oil receiving and discharging port. The Photo-119, 120 shows typical oil receiving to tank.

Photo- 119: Oil receiving pipe

http://www.ilo.org/safework_bookshelf/english?content&nd=857171254

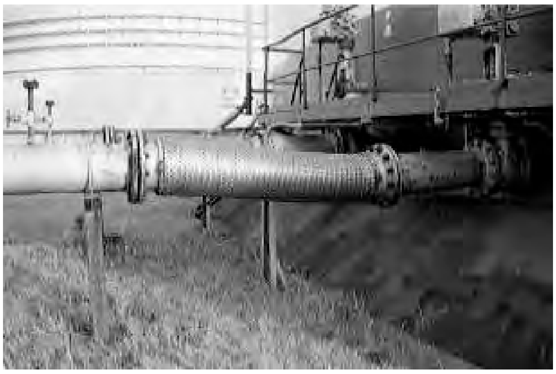


Photo- 120: In/out expansion with oil tank

http://www.hrr.mlit.go.jp/bosai/niigatajishin/contents/c27c.html

Article 113. Safety measure for oil terminal

Article 113-1. Indication

1. Since the oil storage base store hazardous materials and there is a risk of fire and explosion, the site must be enclosed by a fence, prohibited the entrance along with other than the authorized and warning "not enter without permission" must displayed as shown in Photo-121, 122.

Photo- 121: Fence and warning around oil tank

http://www.geolocation.ws/v/W/4d7b063287865614d503789c/storage-tank-ks-1-the-public-footpath-to/en

Photo- 122: Fence and warning around oil tank

http://www.123rf.com/photo_407240_oil-storage-plant-and-sign.html

Article 113-2. Safety measures

1. Prevention of leakage

1.1 Oil fence

Oil fence as shown in Photo-123, 124 must be expanded around the tanker including berth to prevent pollution of the sea due to oil spillage during oil unloading even if it flows out to sea.

Photo- 123: Oil fence

http://cestlavie2.blog.eonet.jp/baron3/2009/12/

Photo- 124: Oil fence

http://www.sanwaeng.co.jp/6.htm

1.2 Oil-proof dike

The oil-proof dike which can be accumulate up to 110% or more of volume of oil (more than 0.5m in height) around the tank must be established to prevent the spread of spill to measure the leakage of oil from the tank when the event as shown in Photo-125, 126 and 127. Important point about this dike is installation of the drainage valve for congestion water in the dike and the auto-sensing equipment for spilled oil as shown in Fig-49.

Photo- 125: Oil tank dike

http://www.advancedmodelrailroad.com/servlet/the-3143/HO-Scale--dsh--WIDE/Detail

Photo- 126: Oil tank dike

http://www.taisei.co.jp/works/jp/data/1170045620493.html

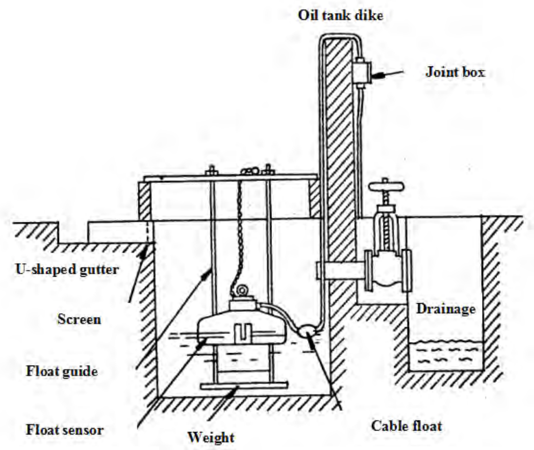


Fig- 49: Auto-sensing equipment for spilled oil

Reference: P-125 of Journal (No.516: Sept. /1999) TENPES

Photo- 127: Outdoor oil storage tank

http://www.arabianoilandgas.com/article-5870-petrochemicals_focus_storage_tank_farms/

1.3 Oil spill prevention dike

This is also called the secondary oil spill prevention dike in order to prevent the spill to outside the boundary even if dike is broken. When installing the oil spill prevention dike (more than 0.3m in height) as shown in Photo-128 and 129, it is necessary to pay sufficient attention to consideration of facility of fire and leakage to outskirt through drainage line of storm water.

Photo- 128: Oil tank dike

http://www.shibushi.co.jp/safety/index.html

Photo- 129: Oil tank dike

http://www.hrr.mlit.go.jp/bosai/niigatajishin/contents/c27c.html

1.4 Oil separation tank

Wastewater from fuel oil facility and rainwater may be contained even slightly oily. Therefore, water pollution must be prevented by removing the oil as provided in the guide vanes or oil separation tank in order to prevent discharge directly outside the premises as shown in Fig-50 and Photo-130. Oil separation is performed by removal depending on the density difference between drainage and oil droplets.

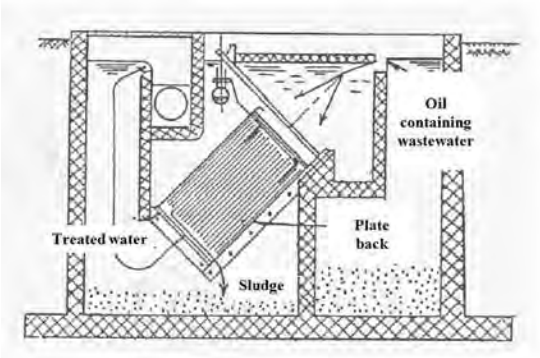


Fig- 50: CPI type oil separator

Reference: P-126 of Journal (No.516: Sept. /1999) TENPES

Photo- 130: API oil separator

http://www.shibushi.co.jp/safety/index.html

1.5 Others

1.5.1 Pipings and valves must be the welding type.

Leakage due to corrosion must be prevented by anti-corrosion painting or cathodic protection. Also, height of piping rack must be considered in terms of corrosion.

2. Prevention of fire and explosion

This is particularly important when handling naphtha and crude oil, etc. which has a lot of volatiles and the fire ignition source that cause the explosion must be removed.

2.1 Explosion proof construction of electrical products

In principle, electrical products used for the fuel equipment must be installed non-hazardous location as much as possible; explosion proof one must be installed when installing them in a hazardous area.

2.2 Antistatic

Oil causes static electricity by friction due to flowing in the pipe and it may lead to fire or explosion by a source of static electricity ignition. It is necessary to reduce generation, neutralize or disclose generated static electricity quickly and limit the charging or accumulation in order to prevent this. Therefore, the flow velocity in the pipe must be reduced (such as when receiving, it must be less than 1m/sec), the receiving pipe to tank must be extended to near the bottom of tank and be avoided hitting the oil level with oil. In addition, piping and equipments must be performed reliable grounding and the measure for anti-static electricity must be taken by means of removing of impurities such as drain and measures to prevent static electricity. Also, it is necessary to note to prevent generation and charging of static electricity by means of wearing anti-static clothing and eliminating static electricity by contact with ground rods in case of static electricity in the human body.

2.3 Ventilation

Gas of naphtha, crude oil and the like is nearly as gas of gasoline, it ignite naturally at 250~300^{o}C, since the lower limit of combustion limit is about 1.4% and a specific gravity has 3.5 times of the air.

Therefore, consideration must be given so that no gas leaks and adequate ventilation around each facility.

2.4 Others

It is necessary to provide lightening protection system in case of lightning as well as installing the frame arrester to prevent flash frames in order to prevent fire and explosion. Fig-52, 53, 54 and Table-17 shows a typical application example of the frame arrestors which are applied to oil receiving and reservoir.

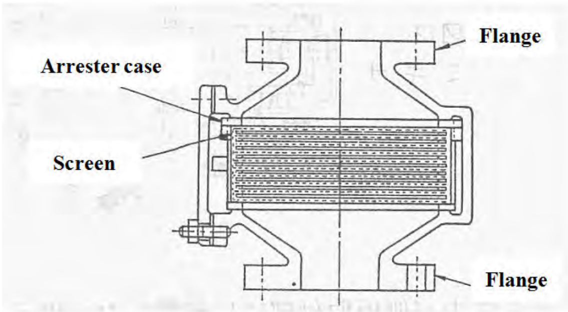


Fig- 51: Frame arrester

Reference: P-126 of Journal (No.516: Sept. /1999) TENPES

Fig- 52: Inline frame arrester

http://www.valve.ie/flame.htm

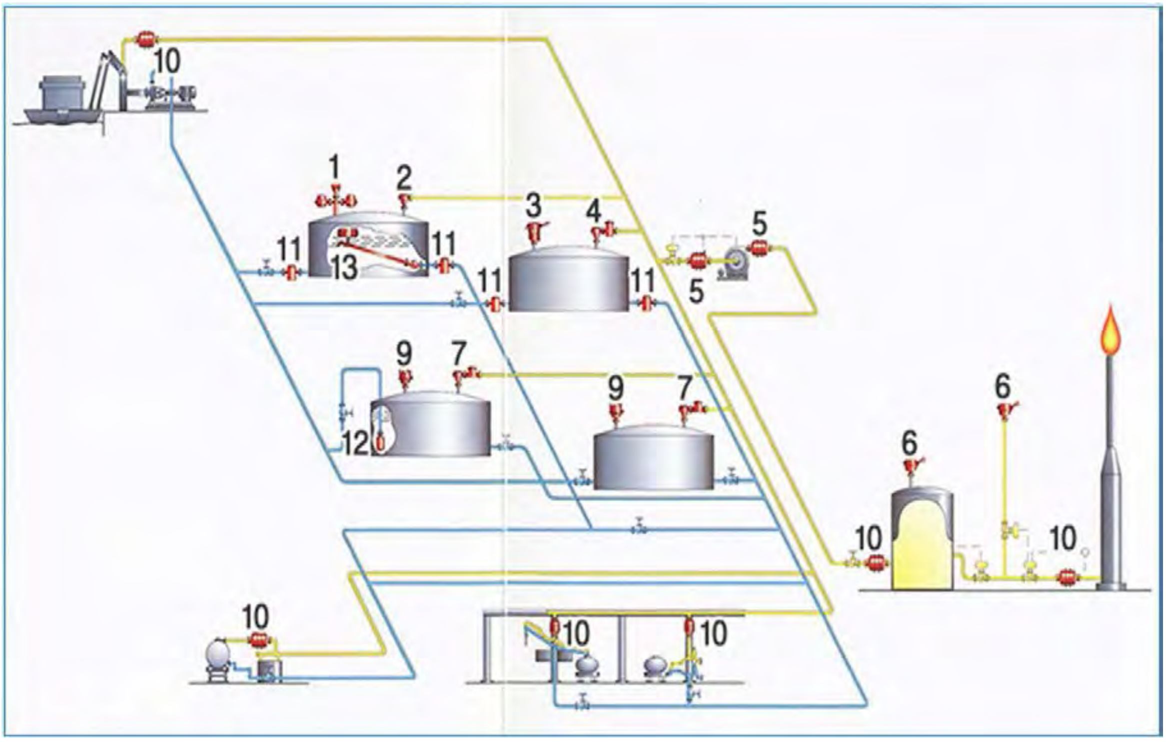


Fig- 53: Typical arrangement of frame arrester

Table- 17: Type of frame arrester

1.	combination fire protection from intrusion in the storage tank vents	(left-hand side) frame arrester for end of line + (right-hand side) negative pressure relief valve (with frame arrestor mechanism)
2.	Protection from detonation to occur in the pipeline	Frame arrester for detonation (type to install on the tank)
3.	Fire protection from intrusion in the storage tank vents	Breather valve with integrated frame of arrester for end of line
4.	Prevention from detonation combination of vents into the piping	(left-hand side) frame arrester for detonation + (right-hand side) negative pressure relief valve (with frame arrestor mechanism)
5.	Prevent backfire from combustion equipment	Frame arrester for deflagration (differential pressure monitor, temperature monitor, with a steam nozzle for cleaning)
6.	Fire protection from intrusion in the free ventilation of the storage tank vent valve	Frame arrester for end of line
7.	Protection from detonation combination of vents into the piping	(left-hand side) frame arrester for detonation + (right-hand side) with positive pressure relief valve with check valve mechanism
8.	Protection from detonation to occur in the pipeline	Frame arrester for detonation
9.	Fire protection from intrusion in the storage tank vents	Liquid diaphragm type breather valve (with frame arrestor mechanism, and anti-icing mechanism)
10.	Protection against both detonation from occurring in the pipeline	Frame arrestor for detonation (corresponding both direction type)
11.	Filling of storage tanks, protection from the detonation of the sample line	Frame arrester for detonation (for liquids)
12.	Filling of storage tanks, protection from the detonation of the sample line	Frame arrester for detonation (installed in the tank for the liquid type)
13.	Float swivel joint pipe systems for liquid extraction	

3. Prevention of spread of the incident

3.1 Firefighting equipment

The air bubbles firefighting equipment is the typical method for extinguishing oil fires. This will shut off the air while burning surface is covered with foam to suppress the generation of gas, in addition, have a cooling effects that is caused by moisture contained in the bubble as shown in Fig-55, 56. There are an air bubble type and chemical foam type as a foam extinguishing agent. It has been decided to use a protein foam extinguishing agent or water deposition of air foam fire extinguishing agent. This air bubble fire extinguishing equipment has been used for since ancient times such as fixed fire extinguishing system of tank and monitor nozzle equipment around the berth. In addition, it is applied around the pump and flow meter, powder fire extinguishing equipment. In the large oil storage base, it is necessary to deploy a set of so-called three-point vehicle, the form undiluted solution chemical transporter, the large chemical fire engine and the large aerial water cannon truck.

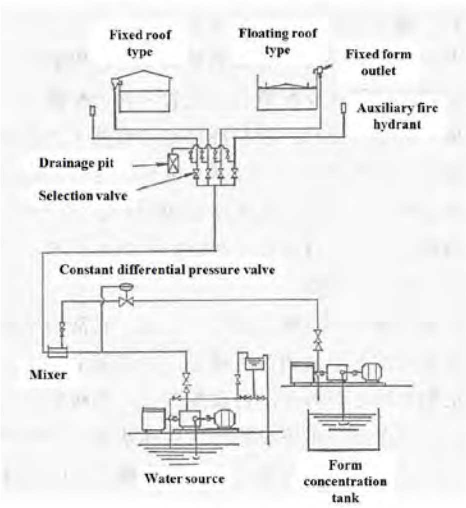


Fig- 54: Bubble extinguishing system

Reference: P-127 of Journal (No.516: Sept. /1999) TENPES

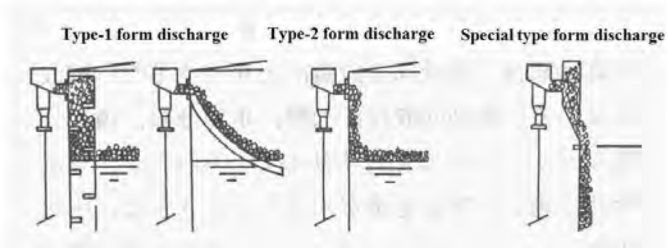


Fig- 55: Example of fixed foam outlet

Reference: P-127 of Journal (No.516: Sept. /1999) TENPES

High-performance precoat fire fighting system of oil tanks consist of pipelines, put into a tank. The pipeline is equipped with: full-opening valve, safety bursting disk, reverse valve and high-pressure foamer, connected with fire-extinguishing tank truck (or with automatic fire fighting system) with water tank, fluorine synthetically foaming agent tank and mixer pump as shown in Phot-131 and Fig-57.

Photo- 131: Form undiluted solution chemical tank

http://www.shibushi.co.jp/safety/index.html

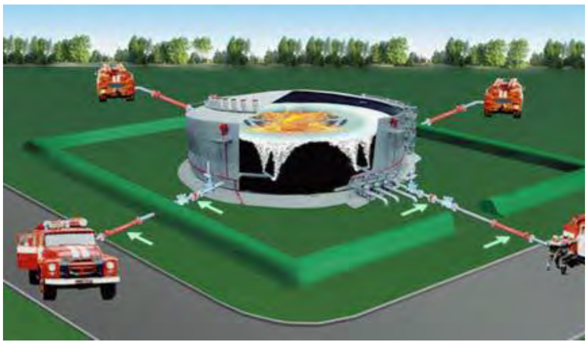


Fig- 56: Firefighting by form

http://tomzel.ru/en/9/

3.2 Tank cooling water equipment

It is preferable to install the cooling water sprinkle equipment on the roof or side wall of tank in order to protect from radiation heat around fire. Upon installation of sprinkling facilities, which are selected by about 2ℓ/minm^2 uniformly in the total surface area, it is necessary to select the proper amount depending on distance to tank. Also, water curtain equipment must be installed for the purpose of protection from radiant heat as shown in Fig-58. Sufficient attention must be required when using seawater in discriminately for function test, etc., since it cause corrosion, although seawater is often used as source of water because it is necessary to use plenty of water.

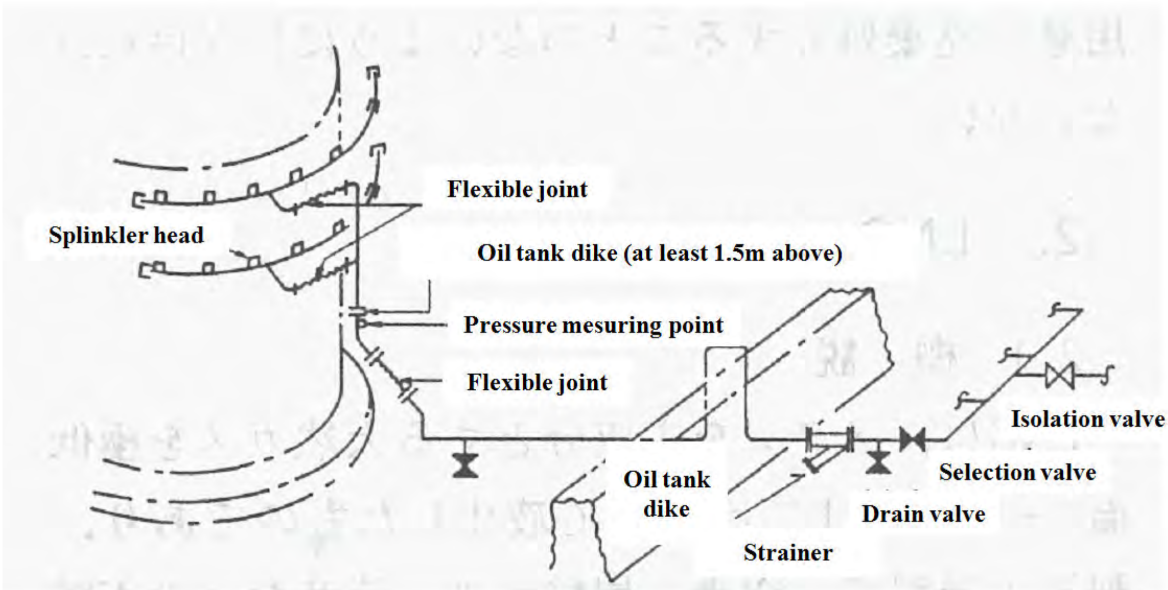


Fig- 57: Tank cooling water equipment

Reference: P-127 of Journal (No.516: Sept. /1999) TENPES

3.3 Gas leak detector

It is important to seek early detection of anomalies to prevent expansion of disasters. The installation of gas leak detector is an effective way for equipment for oil which has much volatile and is highly flammable such as naphtha and crude oil, etc. This is installed as alarm below the lower limit concentration of combustion (lower limit concentration of 20~30%) by means of installing suction at ground portion of valves, joint flange with equipments and places where gas tends to leak or leaked gas stagnant. In addition, installation of automatic fire detector is also effective for early detection of fires.

3.4 Others

It must be taken care sufficiently when planning placement of equipments such as separation distance between tanks and other security property, border, including open space and ensure retention of the road disaster prevention.

Chapter-3. Comparison of Technical Standards for pipeline

The comparison table of technical standard for gas and oil pipeline is shown in Table-18.

Table- 18: Pipeline industry standards incorporated by reference in 49 CFR part 192, 193 and 195

SDO acronomy	Standards	Title	Latest edition	Federal reference
American Gas Association (AGA)	AGA XK0101	Purging principles and practices	3rd Edition, 2001	§§193.2513; 193.2517; 193.2615
American Petroleum Institute (API)	ANSI/API Spec 5L/ISO 3183	Specification for line pipe	47th Edition 2007	§§192.55 (e); 192.113; item-1 of Appendix-B
(API)	RP5L1	Recommended Practice for Railroad Transportation of Line Pipe	6th Edition, 2002	§ 192.65(a)
(API)	RP5LW	Recommended Practice for Transportation of Line Pipe on Barges and Marine Vessel...	2nd Edition 1996	§ 192.65(b)
(API)	Spec. 6D/ISO 14313	Pipeline Valves	23rd Edition and Errata June 2008	§ 192.145(a)
(API)	RP 80	Guidelines for the Definition of Onshore Gas Gathering Lines	1st Edition, 2000	§§192.8(a); 192.8(a)(1); 192.8(a)(2); 192.8(a)(3); 192.8(a)(4). 192.8(a); 192.8(a ...
(API)	Std. 1104	Welding of Pipelines and Related Facilities	20th Edition and Errata2, 2008	§§ 192.227(a); 192.229(c)(1); 192.241(c); Item -2, Appendix-B
(API)	RP1162	Public Awareness Programs for Pipeline Operators	1st Edition, 2003	§§ 192.616(a); 192.616(b); 192.616(c)
(API)	ANSI/API Spec. 12F	Specification for Shop Welded Tanks for Storage of Production Liquids	11th Edition and Errata, 2007	§§195.132(b)(1); 195.205(b)(2); 195.264(b)(1); 195.264(e)(1); 195.307(a); 195.56 ...
(API)	Stan. 510	Pressure Vessel Inspection Code: Maintenance Inspection, Rating, Repair, and Alt ...	9th Edition, 2006	§§195.205(b)(3); 195.432(c).

SDO acronomy	Standards	Title	Latest edition	Federal reference
(API)	Stan. 620	Design and Construction of Large, Welded, Low- Pressure Storage Tanks	11th Edition, 2008	§§195.132(b)(2); 195.205(b)(2); 195.264(b)(1); 195.264(e)(3); 195.307(b).
(API)	Stan. 650	Welded Steel Tanks for Oil Storage	11th Edition, 2007	§§195.132(b)(3); 195.205(b)(1); 195.264(b)(1); 195.264(e)(2); 195.307I; 195.307(...
(API)	RP651	Cathodic Protection of Aboveground Petroleum Storage Tanks	3rd Edition, Jan. 2007	§§195.565; 195.579(d).
(API)	RP652	Lining of Aboveground Petroleum Storage Tank Bottoms	3rd edition, Oct. 2005	§195.579(d).
(API)	Stan. 653	Tank Inspection, Repair, Alteration, and Reconstruction	3rd Edition, Addendum 1-3 and Errata,2008	§§195.205(b)(1); 195.432(b).
(API)	Stan. 1130	Computational Pipeline Monitoring for Liquid Pipelines	1st edition, September, 2007	§§195.134; 195.444.
(API)	Stan. 2000	Venting Atmospheric and Low-Pressure Storage Tanks	5th Edition and Errata, 1999	§§195.264(e)(2); 195.264(e)(3).
(API)	RP2003	Protection Against Ignitions Arising Out of Static, Lightning, and Stray Current...	7th Edition, 2008	§195.405(a).
(API)	Stan. 2026	Safe Access/Egress Involving Floating Roofs of Storage Tanks in Petroleum Service ...	2nd Edition, Reaffirmation, 2006	§195.405(b).
(API)	RP2350	Overfill Protection for Storage Tanks In Petroleum Facilities	3rd Edition, Jan. 2005	§195.428I.
(API)	Stan. 2510	Design and Construction of LPG Installations	8th Edition, 2001	§§195.132(b)(3); 195.205(b)(3); 195.264(b)(2); 195.264(e)(4); 195.307(e);195.428 . ..

SDO acronomy	Standards	Title	Latest edition	Federal reference
American Society of Mechanical Engineers (ASME)	B16.1–2005	ANSI/ASME B16.1-2005 Gray Iron Pipe Flanges and Flanged Fittings: Classes 25, 12...	2006 Edition	§192.147(c).
(ASME)	B16.5–2003	Pipe Flanges and Flanged Fittings	2003 Edition	§§192.147(a); 192.279.
(ASME)	B16.9–2007	Factory-Made Wrought Steel Butt Welding Fittings	2007 Edition	§195.118(a).
(ASME)	B31.4–2006	Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids	2006 Edition	§195.452(h)(4)(i).
(ASME)	B31G–1991	Manual for Determining the Remaining Strength of Corroded Pipelines	1991 Edition	§§192.485(c); 192.933(a).; §§195.452(h)(4)(i)(B); 195.452(h)(4)(iii)(D).
(ASME)	B31.8–2007	Gas Transmission and Distribution Piping Systems	2007 Edition	§192.619(a)(1)(i).; §195.5(a)(1)(i); 195.406(a)(1)(i).
(ASME)	B31.8S–2004	Supplement to B31.8 on Managing System Integrity of Gas Pipelines	2004 Edition	§§192.903(c); 192.907(b); 192.911, Introductory text; 192.911(i); 192.911(k); 19 ...
(ASME)	ASME Section I	ASME Boiler and Pressure Vessel Code, Section I, "Rules for Construction of Power ...	2007 Edition	§192.153(a).
(ASME)	ASME Section VIII - DIV. 1	ASME Boiler and Pressure Vessel Code, Section-8, Division 1, Rules for Constr ...	2007 Edition	§§192.153(a); 192.153(b); 192.153(d); 192.165(b)(3).; §193.2321; §§195.124; 195. ...
(ASME)	ASME Section VIII - Div. 2	ASME Boiler and Pressure Vessel Code, Section-8, Division-2, Rules for Constr ...	2007 Edition	§§192.153(b); 192.165(b)(3); §193.2321; §195.307(e).
(ASME)	AMSE Section-9	ASME Boiler and Pressure Vessel Code, Section-9, Welding and Brazing Qualificat ...	2007 Edition	§§192.227(a); Item-2, Appendix-B.; §195.222.

SDO acronomy	Standards	Title	Latest edition	Federal reference
American Society for Testing and Materials (ASTM)	A53/A53M–07	Standard Specification for Pipe, Steel, Black and Hot- Dipped, Zinc- Coated, Welde...	2007 Edition	§§192.113; Item-1, Appendix-B.; §195.106(e).
(ASTM)	A106/A106M–08	Standard Specification for Seamless Carbon Steel Pipe for High- Temperature Servi ...	2008 Edition	§§192.113; Item-1, Appendix-B.; §195.106(e).
(ASTM)	A333/A333M–05	Standard Specification for Seamless and Welded Steel Pipe for Low- Temperature Se ...	2005 Edition	§§192.113; Item -1, Appendix-B.; §195.106(e).
(ASTM)	A372/A372M–08	Standard Specification for Carbon and Alloy Steel Forgings for Thin-Walled Press ...	2008 Edition	§192.177(b)(1).
(ASTM)	A381–96	Standard Specification for Metal-Arc Welded Steel Pipe for Use With High- Pressur ...	2005 Edition	§§192.113; Item-1, Appendix-B.; §195.106(e).
(ASTM)	A671–06	Standard Specification for Electric-Fusion-Welded Steel Pipe for Atmospheric and ...	2006 Edition	§§192.113; Item-1, Appendix-B.; §195.106(e).
(ASTM)	A672–08	Standard Specification for Electric-Fusion-Welded Steel Pipe for High-Pressure S ...	2008 Edition	§§192.113; Item-1, Appendix-B.; §195.106(e).
(ASTM)	A691–98	Standard Specification for Carbon and Alloy Steel Pipe, Electric-Fusion-Welded f ...	2007 Edition	§§192.113; Item-1, Appendix-B.; §195.106(e).
(ASTM)	D638–03	Standard Test Method for Tensile Properties of Plastics	2003 Edition	§§192.283(a)(3); 192.283(b)(1).
(ASTM)	D2513–87	Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings	1987 Edition	§192.63(a)(1).
(ASTM)	D2513–99	Standard Specification for Thermoplastic Gas Pressure Pipe, Tubing, and Fittings	1999 Edition	§§192.191(b); 192.281(b)(2); 192.283(a)(1)(i); Item-1, Appendix-B.
(ASTM)	D2517–00	Standard Specification for Reinforced Epoxy Resin Gas Pressure Pipe and Fittings	2000 Edition	§§192.191(a); 192.281(d)(1); 192.283(a)(1)(ii); Item-1, Appendix-B.
(ASTM)	F1055–98	Standard Specification for Electrofusion Type Polyethylene Fittings for Outside ...	1998 Edition	§192.283(a)(1)(iii).
Gas	GRI 02/0057	Internal Corrosion Direct	2002 Edition	§192.927(c)(2).

SDO acronomy	Standards	Title	Latest edition	Federal reference
Technology Institute (GTI)		Assessment of Gas Transmission Pipelines Methodology		
Gas Technology Institute (GTI)	GTI-04/0032	LNGFIRE: A Thermal Radiation Model for LNG Fires	2004 Edition	§193.2057.
Gas Technology Institute (GTI)	GTI–04/0049	LNG VaporDispersion Prediction with the DEGADIS2.1: Dense Gas Dispersion Model ...	2004 Edition	§193.2059.
(GTI)	GRI–96/0396.5	Evaluation of Mitigation Methods for Accidental LNG Releases, Volume 5: Using FE ..	1996 Edition	§193.2059.
Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (...	SP-44-2006	Steel Pipe Line Flanges	2006 Edition	§192.147(a).
Manufacturers Standardization Society of the Valve and Fittings Industry, Inc. (...	SP–75–2004	Specification for High Test Wrought Butt Welding Fittings	2004 Edition	§195.118(a).
National Association of Corrosion Engineers (NACE)	SP0169–2007	Control of External Corrosion on Underground or Submerged Metallic Piping System ...	2007 Edition	§§195.3; 195.571; 195.573(a)(2)
(NACE)	SP0502–2008	Pipeline External Corrosion Direct Assessment Methodology	2008 Edition	§§ 192.923; 192.925; 192.931; 192.935; 192.939
National Fire Protection Association (NFPA)	NFPA 30	Flammable and Combustible Liquids Code	2008 Edition	§192.735(b); §195.264(b)(1).
(NFPA)	NFPA 58	Liquefied Petroleum Gas Code (LP-Gas Code)	2004 Edition	§192.11(a); 192.11(b); 192.11(c).
(NFPA)	NFPA 59	Utility LP-Gas Plant Code	2004 Edition	§§192.11(a); 192.11(b); 192.11(c).
(NFPA)	NFPA 70	National Electrical Code	2008 Edition	§§192.163(e);

SDO acronomy	Standards	Title	Latest edition	Federal reference
				192.189(c).
(NFPA)	NFPA 59A	Standard for the Production, Storage, and Handling of Liquefied Natural Gas(LNG ...	2001 Edition	§§193.2019; 193.2051; 193.2057; 193.2059; 193.2101; 193.2301; 193.2303; 193.2401 ...
Plastics Pipe Institute, Inc. (PPI)	TR–3/2008	Policies and Procedures for Developing Hydrostatic Design Basis(HDB), Pressure ...	2008 Edition	§192.121.
American Gas Association (AGA)	RSTRENG 3.0 User's Manual and Software (Includes: L51688B, Modified Criterion fo ...	A Modified Criterion for Evaluating the Remaining Strength of Corroded Pipe	1993 Edition	§§192.933(a)(1); 192.485(c).
American Petroleum Institute (API)	ANSI/API RP 2RD	Design of Risers for Floating Production Systems(FPSs) and Tension-Leg Platform ...	1st	N/A
American Petroleum Institute (API)	ANSI/API RP 1110	Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas...	5th	N/A
(API)	Pub 1161	Guidance Document for the Qualification of Liquid Pipeline Personnel	1st	N/A
(API)	Std 1163	In-Line Inspection Systems Qualification Standard	1st	N/A
(API)	RP 1165	Recommended Practices for Pipeline SCADA Displays	1st	N/A
(API)	RP 1167	Alarm Management	1st	N/A
(API)	RP 1168	Pipeline Control Room Management	1st	N/A
American Society of Mechanical Engineers (ASME)	ANSI/ASME B31Q	Pipeline Personnel Qualification	2006	N/A
American Society for Nondestructive Testing (ASNT)	ANSI/ASNT ILI-PQ	In-line Inspection Personnel Qualification and Certification	2005	N/A
National	RP 0102	In-line Inspection of Pipelines	2002	N/A

SDO acronomy	Standards	Title	Latest edition	Federal reference
Association of Corrosion Engineers (NACE)				
(NACE)	TG 256	"Electrodes, Field-Grade Test Methods“Internal Corrosion Direct	Under Development	N/A
(NACE)	NACE SP0206	Assessment Methodology for Pipelines Carrying Normall ...	2006	N/A
(NACE)	NACE SP0208	Internal Corrosion Direct Assessment Methodology for Liquid Petroleum Pipelines	2008	N/A
Gas Piping Technology Committee (GPTC)	ANSI/GPTC Z380.1	Guide for Gas Transmission and Distribution Piping Systems	2003 Addenda 1 through 12	N/A
Gas Piping Technology Committee (GPTC)	ANSI/GPTC Z380.1	DIMP Guidance		N/A
National Association of Corrosion Engineers (NACE)	SP0106-2006	Internal Corrosion Control in Pipelines		192
(NACE)	TM0106-2006	Detection, Testing and Evaluation of Micorbially Inlfuenced Corrosion(MIC) on E ...		192 and 195
(NACE)	SP0207	Performing Close-Interval Potential Surveys and DC Surface Potential Gradient Su ...		192 and 195
(NACE)	SP0200-2008 (formerly RP0200)	Steel-Cased Pipelines Practices		195

The reference international standards for designing oil fuel handling facility are organized in Table-19.

Table- 19: Reference International Technical Standards

Number	Rev.	Title	Content
ISO 13623	2009	Petroleum and natural gas industries—Pipeline transportation systems	ISO 13623:2009 specifies requirements and gives recommendations for the design, materials, construction, testing, operation, maintenance and abandonment of pipeline systems used for transportation in the petroleum and natural gas industries. ISO 13623:2009 applies to pipeline systems on land and offshore, connecting wells, production plants, process plants, refineries and storage facilities, including any section of a pipeline constructed within the boundaries of such facilities for the purpose of its connection. A figure shows the extent of pipeline systems covered by ISO 13623:2009. ISO 13623:2009 applies to rigid, metallic pipelines. It is not applicable for flexible pipelines or those constructed from other materials, such as glass-reinforced plastics. ISO 13623:2009 is applicable to all new pipeline systems and can be applied to modifications made to existing ones. It is not intended that it apply retroactively to existing pipeline systems. ISO 13623:2009 describes the functional requirements of pipeline systems and provides a basis for their safe design,

Number	Rev.	Title	Content
			construction, testing, operation, maintenance and abandonment.
ISO 15649	2001	Petroleum and natural gas industries—Piping	**1.1** This International Standard specifies the requirements for design and construction of piping for the petroleum and natural gas industries, including associated inspection and testing. **1.2** This International Standard is applicable to all piping within facilities engaged in the processing or handling of chemical, petroleum, natural gas or related products. EXAMPLE Petroleum refinery, loading terminal, natural gas processing plant (including liquefied natural gas facilities), offshore oil and gas production platforms, chemical plant, bulk plant, compounding plant, tank farm. **1.3** This International Standard is also applicable to packaged equipment piping which interconnects individual pieces or stages of equipment within a packaged equipment assembly for use within facilities engaged in the processing or handling of chemical, petroleum, natural gas or related products. **1.4** This International Standard is not applicable to transportation pipelines and associated plant.
ISO 13628	2011	Petroleum and natural gas industries -- Design and operation of subsea production systems -- Part 15: Subsea structures and manifolds	ISO 13628-15:2011 addresses recommendations for subsea structures and manifolds, within the frameworks set forth by recognized and accepted industry specifications and standards. As such, it

Number	Rev.	Title	Content
			does not supersede or eliminate any requirement imposed by any other industry specification. ISO 13628-15:2011 covers subsea manifolds and templates utilized for pressure control in both subsea production of oil and gas, and subsea injection services.
ISO 13628-1	2005	Petroleum and natural gas industries -- Design and operation of subsea production systems -- Part 1: General requirements and recommendations	ISO 13628-1:2005 provides general requirements and overall recommendations for development of complete subsea production systems, from the design phase to decommissioning and abandonment. ISO 13628-1:2005 is intended as an umbrella document to govern other parts of ISO 13628 dealing with more detailed requirements for the subsystems which typically form part of a subsea production system. However, in some areas (e.g. system design, structures, manifolds, lifting devices, and color and marking) more detailed requirements are included herein, as these subjects are not covered in a subsystem standard. The complete subsea production system comprises several subsystems necessary to produce hydrocarbons from one or more subsea wells and transfer them to a given processing facility located offshore (fixed, floating or subsea) or onshore, or to inject water/gas through subsea wells. ISO 13628-1:2005 and its related subsystem standards apply as far as the interface limits described in Clause 4. Specialized equipment, such as split trees and trees and manifolds in atmospheric chambers, are not specifically discussed because of their

Number	Rev.	Title	Content
			limited use. However, the information presented is applicable to those types of equipment.
ISO 13628-2	2006	Petroleum and natural gas industries -- Design and operation of subsea production systems -- Part 2: Unbonded flexible pipe systems for subsea and marine applications	ISO 13628-2:2006 defines the technical requirements for safe, dimensionally and functionally interchangeable flexible pipes that are designed and manufactured to uniform standards and criteria. Minimum requirements are specified for the design, material selection, manufacture, testing, marking and packaging of flexible pipes, with reference to existing codes and standards where applicable. ISO 13628-2:2006 applies to unbonded flexible pipe assemblies, consisting of segments of flexible pipe body with end fittings attached to both ends. ISO 13628-2:2006 applies to both static and dynamic flexible pipes used as flowlines, risers and jumpers. The applications addressed by this ISO 13628-2:2006 are sweet and sour service production, including export and injection applications for production products including oil, gas, water and injection chemicals. ISO 13628-2:2006 does not cover flexible pipes of bonded structure or flexible pipe ancillary components or to flexible pipes for use in choke-and-kill line applications.
ISO 13628-3	2000	Petroleum and natural gas industries -- Design and operation of subsea production systems -- Part 3: Through flowline (TFL) systems	—

Number	Rev.	Title	Content
ISO 14556	2000	Steel -- Charpy V-notch pendulum impact test -- Instrumented test method	—
ISO 148	2009	Metallic materials -- Charpy pendulum impact test -- Part 1: Test method	ISO 148-1:2009 specifies the Charpy pendulum impact (V-notch and U-notch) test method for determining the energy absorbed in an impact test of metallic materials.
ISO 3183	2007	Petroleum and natural gas industries -- Steel pipe for pipeline transportation systems	ISO 3183:2007 specifies requirements for the manufacture of two product specification levels (PSL 1 and PSL 2) of seamless and welded steel pipes for use in pipeline transportation systems in the petroleum and natural gas industries.
ISO 7005-1	2011	Pipe flanges -- Part 1: Steel flanges for industrial and general service piping systems	ISO 7005-1:2011 establishes a base specification for pipe flanges suitable for general purpose and industrial applications including, but not limited to, chemical process industries, electric power generating industries, petroleum and natural gas industries. It places responsibility for the selection of a flange series with the purchaser. It is applicable to flanges within facilities engaged in the processing or handling of a wide variety of fluids, including steam, pressurized water and chemical, petroleum, natural gas or related products. ISO 7005-1:2011 is also applicable to packaged equipment piping, which interconnects individual pieces or stages of equipment within a packaged equipment assembly for use within facilities engaged in the processing or handling of a variety of fluids, including steam and chemical, petroleum, natural gas or related products

Number	Rev.	Title	Content
ISO 10474	1991	Steel and steel products _Inspection documents.	Defines the different types of inspection documents supplied to the purchaser. Shall be used in conjunction with: ISO 404 for steel and steel products; ISO 4990 for steel castings.
ISO 13847	2000	Petroleum and natural gas industries _ Pipeline transportation systems _ Field and shop welding of pipelines.	—
ISO 14313	2007	Petroleum and natural gas industries _Pipeline transportation systems _Pipeline valves	ISO 14313:2007 specifies requirements and provides recommendations for the design, manufacturing, testing and documentation of ball, check, gate and plug valves for application in pipeline systems meeting the requirements of ISO 13623 for the petroleum and natural gas industries. ISO 14313:2007 is not applicable to subsea pipeline valves, as they are covered by a separate International Standard (ISO 14723).
ISO 14723	2009	Petroleum and natural gas industries _Pipeline transportation systems _Subsea pipeline valves.	ISO 14723:2009 specifies requirements and gives recommendations for the design, manufacturing, testing and documentation of ball, check, gate and plug valves for subsea application in offshore pipeline systems meeting the requirements of ISO 13623 for the petroleum and natural gas industries.
ISO 15761	2002	Steel gate, globe and check valves for sizes DN 100 and smaller, for the petroleum and natural gas industries	ISO 15761 specifies the requirements for a series of compact steel gate, globe and check valves for petroleum and natural gas industry applications. It is applicable to valves of nominal sizes (DN) 8, 10, 15, 20, 25, 32, 40, 50, 65, 80 and 100, to corresponding nominal sizes, to nominal pipe sizes (NPS) of a quarter, three eighths, half, three quarters, one, one and a quarter, one and a half, two, two and a half, three and four, and to pressure designation classes 150, 300, 600,

Number	Rev.	Title	Content
			800 and 1500. It includes provisions for a wide range of valve characteristics and is applicable to valve end flanges in accordance with ASME B16.5 and valve body ends having tapered pipe threads to ISO 7-1 or ASME B1.20.1.
ISO 17292	2004	Metal ball valves for petroleum, petrochemical and allied industries	ISO 17292:2004 specifies the requirements for a series of metal ball valves suitable for petroleum, petrochemical, natural gas plants, and related industrial applications. It covers valves of the nominal sizes DN 8, 10, 15, 20, 25, 32, 40, 50, 65, 80, 100, 150, 200, 250, 300, 350, 400, 450 and 500, corresponding to nominal pipe sizes NPS 1/4, 3/8, 1/2, 3/4, 1, 1 1/4, 1 1/2, 2, 2 1/2, 3, 4, 6, 8, 10, 12, 14, 16, 18 and 20, and is applicable for pressure designations of Class 150, 300, 600 and 800 (the last applicable only for valves with reduced bore and with threaded and socket welding end), and PN 16, 25 and 40.
IEC 60079-10	2002	Electrical apparatus for explosive gas atmospheres _ Part 10: Classification of hazardous areas.	Is concerned with the classification of hazardous areas where flammable gas or vapor risks may arise, in order to permit the proper selection and installation of apparatus for use in such hazardous areas.
IEC 60079-14	2007	Electrical apparatus for explosive gas atmospheres _ Part 14: Electrical installations in hazardous areas (other than mines).	This part of IEC 60079 contains the specific requirements for the design, selection and erection of electrical installations in hazardous areas associated with explosive atmospheres. Where the equipment is required to meet other environmental conditions, for example, protection against ingress of water and resistance to corrosion, additional methods of protection may be necessary. The method used should not adversely affect the integrity of the

Number	Rev.	Title	Content
			enclosure. The requirements of this standard apply only to the use of equipment under normal or near normal atmospheric conditions. The significant technical changes with respect to the previous edition are: Equipment Protection Levels (EPLs) have been introduced and are explained in the new Annex I and dust requirements included from IEC 61241 14, Ed. 1.0.
ASME B31.3	2010	Process piping.	Rules for piping typically found in petroleum refineries; chemical, pharmaceutical, textile, paper, semiconductor, and cryogenic plants; and related processing plants and terminals. This code prescribes requirements for materials and components, design, fabrication, assembly, erection, examination, inspection, and testing of piping. This Code applies to piping for all fluids including: (1) raw, intermediate, and finished chemicals; (2) petroleum products; (3) gas, steam, air and water; (4) fluidized solids; (5) refrigerants; and (6) cryogenic fluids. Also included is piping which interconnects pieces or stages within a packaged equipment assembly.
ASME B31.4	2006	Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids	The B31.4 Code prescribes requirements for the design, materials, construction, assembly, inspection, and testing of piping transporting liquids such as crude oil, condensate, natural gasoline, natural gas liquids, liquefied petroleum gas, carbon dioxide, liquid alcohol, liquid anhydrous ammonia and liquid petroleum products between producers' lease facilities, tank farms, natural gas processing plants, refineries, stations, ammonia plants, terminals (marine, rail and

Number	Rev.	Title	Content
			truck) and other delivery and receiving points. Piping consists of pipe, flanges, bolting, gaskets, valves, relief devices, fittings and the pressure containing parts of other piping components. It also includes hangers and supports, and other equipment items necessary to prevent overstressing the pressure containing parts. It does not include support structures such as frames of buildings, buildings stanchions or foundations Requirements for offshore pipelines are found in Chapter IX. Also included within the scope of this Code are: (A) Primary and associated auxiliary liquid petroleum and liquid anhydrous ammonia piping at pipeline terminals (marine, rail and truck), tank farms, pump stations, pressure reducing stations and metering stations, including scraper traps, strainers, and prover loop; (B) Storage and working tanks including pipe-type storage fabricated from pipe and fittings, and piping interconnecting these facilities; (C) Liquid petroleum and liquid anhydrous ammonia piping located on property which has been set aside for such piping within petroleum refinery, natural gasoline, gas processing, ammonia, and bulk plants; (D) Those aspects of operation and maintenance of liquid pipeline systems relating to the safety and protection of the general public, operating company personnel, environment, property and the piping systems.
ASME B16.5	2009	Pipe flanges and flanged fittings _NPS 1/2 through NPS 24.	This Standard covers pressure-temperature ratings, materials, dimensions, tolerances, marking, testing, and methods of designating

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			openings for pipe flanges and flanged fittings. Included are: flanges with rating class designations 150, 300, 400, 600, 900, and 1500 in sizes NPS 1/2 through NPS 24 and flanges with rating class designation 2500 in sizes NPS 1/2 through NPS 12, with requirements given in both metric and U.S. Customary units with diameter of bolts and flange bolt holes expressed in inch units flanged fittings with rating class designation 150 and 300 in sizes NPS 1/2 through NPS 24, with requirements given in both metric and U.S. Customary units with diameter of bolts and flange bolt holes expressed in inch units flanged fittings with rating class designation 400, 600, 900, and 1500 in sizes NPS 1/2 through NPS 24 and flanged fittings with rating class designation 2500 in sizes 1/2 through NPS 12 that are acknowledged in Nonmandatory Appendix E in which only U.S. Customary units are provided
ASME B16.9	2007	Factory-Made wrought butt-welding fittings	This Standard covers overall dimensions, tolerances, ratings, testing, and markings for wrought carbon and alloy steel factory-made buttwelding fittings of NPS 1/2 through 48. It covers fittings of any producible wall thickness. This standard does not cover low pressure corrosion resistant buttwelding fittings. See MSS SP-43, Wrought Stainless Steel Butt-Welding Fittings. Short radius elbows and returns, which were

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			previously included in ASME B16.28-1994, are included in this standard. B16.9 is to be used in conjunction with equipment described in other volumes of the ASME B16 series of standards as well as with other ASME standards, such as the Boiler and Pressure Vessel Code and the B31 Piping Codes.
ASTM A193A/193M	1998	Standard specification for alloy-steel and stainless steel bolting materials for high temperature service.	This specification covers alloy steel and stainless steel bolting material for pressure vessels, valves, flanges, and fittings for high temperature or high pressure service, or other special purpose applications. Ferritic steels shall be properly heat treated as best suits the high temperature characteristics of each grade. Immediately after rolling or forging, the bolting material shall be allowed to cool to a temperature below the cooling transformation range. The chemical composition requirements for each alloy are presented in details. The steel shall not contain an unspecified element for ordered grade to the extent that the steel conforms to the requirements of another grade for which that element is a specified element. The tensile property and hardness property requirements are discussed, the tensile property requirement is highlighted by a full size fasteners, wedge tensile testing.
ASTM A194A/194M	1998	Standard specification for carbon and alloy steel nuts for bolts for high pressure or high temperature service, or both.	This specification covers a variety of carbon, alloy, and martensitic and austenitic stainless steel nuts. These nuts are intended for high-pressure or high-temperature service, or both. Bars from which the nuts are made shall be hot-wrought. The material may be further processed by centerless grinding or

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			by cold drawing. Austenitic stainless steel may be solution annealed or annealed and strain-hardened. Each alloy shall conform to the chemical composition requirements prescribed. Hardness tests, proof of load tests, and cone proof load tests shall be made to all nuts to meet the requirements specified.
ASTM A350M	2007	Standard specification for carbon and low-alloy steel forgings, requiring notch toughness testing for piping components.	This specification covers several grades of carbon and low alloy steel forged or ring-rolled flanges, forged fittings and valves for low-temperature service. The steel specimens shall be melt processed using open-hearth, basic oxygen, electric furnace or vacuum-induction melting. A sufficient discard shall be made to secure freedom from injurious piping and undue segregation. The materials shall be forged and shall undergo heat treatment such as normalizing, tempering, quenching and precipitation heat treatment. Heat analysis and product analysis shall be performed wherein the steel materials shall conform to the required chemical compositions of carbon, manganese, phosphorus, sulfur, silicon, nickel, chromium, molybdenum, copper, columbium, vanadium, and nitrogen. The materials shall also undergo tension tests and shall conform to the required values of tensile strength, yield strength and elongation. Impact tests shall also be performed and the steel materials shall conform to the required values of minimum impact energy, temperature, and minimum equivalent absorbed energy. Hardness and hydrostatic tests shall also be performed.
API RP 5L1	2002	Railroad transportation of line pipe	The recommendations provided herein apply

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			to the transportation on railcars of API Specification 5L steel line pipe in sizes 23/8 and larger in lengths longer than single random. These recommendations cover coated or uncoated pipe, but they do not encompass loading practices designed to protect pipe coating from damage.
API RP 5L2	2002	Recommended practice for internal coating of line pipe for non-corrosive gas transmission service.	This Recommended Practice provides for the internal coating of line pipe used for non-corrosive natural gas service. It is limited to the application of internal coatings on new pipe prior to installation.
API RP 5LW		Transportation of line pipe on barges and marine vessels	The recommendations in this document apply to transportation of API Specification 5L steel line pipe by ship or barge on both inland and marine waterways, unless the specific requirement of a paragraph in this document references only marine or only inland waterway transport. Inland waterways are defined as those waterways with various degrees of protection, such as rivers, canals, intracoastal waterways, and sheltered bays. These waterways can be fresh or saltwater but are usually traversed by barges. Marine waterways are defined as waterways over open seas with limited or no protection from wind, current, waves, and the like. These areas are normally traversed by sea-going vessels. These recommendations apply to steel line pipe that has 2 $^{3}/_{8}$-in. outside diameter (OD) and larger. These recommendations cover coated or uncoated pipe, but they do not encompass loading practices designed to protect pipe coating from damage. These recommendations are not applicable to

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			pipe-laying vessels or supply vessels. They must be considered as supplementary to the existing rules of governing agencies. These recommendations are supplemental to shipping rules for the convenience of purchasers and manufacturers in the specification of loading and shipping practices and are not intended to inhibit purchasers and manufacturers from using other supplemental loading and shipping practices by mutual agreement.
API RP 1102	2007	Steel pipelines crossing railroads and highways	This recommended practice, Steel Pipelines Crossing Railroads and Highways, gives primary emphasis to provisions for public safety. It covers the design, installation, inspection, and testing required to ensure safe crossings of steel pipelines under railroads and highways. The provisions apply to the design and construction of welded steel pipelines under railroads and highways. The provisions of this practice are formulated to protect the facility crossed by the pipeline, as well as to provide adequate design for safe installation and operation of the pipeline.
API/ANSI 600	1998	Bolted Bonnet Steel Gate Valves for Petroleum and Natural Gas Industries - Modified National Adoption of ISO 10434:1998	This International standard specifies the requirements for a heavy-duty series of bolted bonnet steel gate valves for petroleum refinery and related applications where corrosion, erosion and other service conditions would indicate a need for full port openings, heavy wall sections and large stem diameters.
API 602	2009	Compact Steel Gate Valves - Flanged, Threaded, Welding, and Extended-Body Ends. The standard covers threaded-end,	This standard covers flanged-end, threaded-end, socket-welding-end, and butt-welding-end compact steel gate valves, including extended-body, and bellows seal types, correspond-ing to nominal pipe

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		socket-welding-end, butt-welding-end, and flanged-end compact carbon steel gate valves in sizes NPS4 and smaller.	sizes in ASME B36.10M or ASME B36.19M as defined herein.API publications may be used by anyone desiring to do so. Every effort has been made bythe Institute to assure the accuracy and reliability of the data contained in them; however, theInstitute makes no representation, warranty, or guarantee in connection with this publicationand hereby expressly disclaims any liability or responsibility for loss or damage resultingfrom its use or for the violation of any federal, state, or municipal regulation with which thispublication may conflict.
API Std 620	2008	Design and construction of large, welded, low-pressure storage tanks.	This standard covers the design and construction of large, welded, low-pressure carbon steel above ground storage tanks (including flat-bottom tanks) that have a single vertical axis of revolution. This standard does not cover design procedures for tanks that have walls shaped in such a way that the walls cannot be generated in their entirety by the rotation of a suitable contour around a single vertical axis of revolution. The tanks described in this standard are designed for metal temperatures not greater than 250°F and with pressures in their gas or vapor spaces not more than 15 lbf/in.2 gauge. The basic rules in this standard provide for installation in areas where the lowest recorded 1-day mean atmospheric temperature is –50°F. Appendix S covers stainless steel low-pressure storage tanks in ambient temperature service in all areas, without limit on low temperatures. Appendix R covers low-pressure storage tanks for refrigerated products at temperatures from +40°F to –60°F. Appendix Q covers

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			low-pressure storage tanks for liquefied hydrocarbon gases at temperatures not lower than –270°F. The rules in this standard are applicable to tanks that are intended to (a) hold or store liquids with gases or vapors above their surface or (b) hold or store gases or vapors alone. These rules do not apply to lift-type gas holders. Although the rules in this standard do not cover horizontal tanks, they are not intended to preclude the application of appropriate portions to the design and construction of horizontal tanks designed in accordance with good engineering practice. The details for horizontal tanks not covered by these rules shall be equally as safe as the design and construction details provided for the tank shapes that are expressly covered in this standard.
API Std 650	1993	Welded steel tanks for oil storage.	API Std 650 establishes minimum requirements for material, design, fabrication, erection, and testing for vertical, cylindrical, aboveground, closed- and open-top, welded carbon or stainless steel storage tanks in various sizes and capacities for internal pressures approximating atmospheric pressure (internal pressures not exceeding the weight of the roof plates), but a higher internal pressure is permitted when additional requirements are met. This Standard applies only to tanks whose entire bottom is uniformly supported and to tanks in non-refrigerated service that have a maximum design temperature of 93°C (200°F) or less.

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API Std 1104	2005	Welding of pipelines and related facilities	This standard covers the gas and arc welding of butt, fillet, and socket welds in carbon and low-alloy steel piping used in the compression, pumping, and transmission of crude petroleum, petroleum products, fuel gases, carbon dioxide, nitrogen and, where applicable, covers welding on distribution systems. It applies to both new construction and in-service welding. The welding may be done by a shielded metal-arc welding, submerged arc welding, gas tungsten-arc welding, gas metal-arc welding, flux-cored arc welding, plasma arc welding, oxyacetylene welding, or flash butt welding process or by a combination of these processes using a manual, semiautomatic, mechanized, or automatic welding technique or a combination of these techniques. The welds may be produced by position or roll welding or by a combination of position and roll welding. This standard also covers the procedures for radiographic, magnetic particle, liquid penetrant, and ultrasonic testing, as well as the acceptance standards to be applied to production welds tested to destruction or inspected by radiographic, magnetic particle, liquid penetrant, ultrasonic, and visual testing methods. The values stated in either inch-pound units or SI units are to be regarded separately as standard. Each system is to be used independently of the other, without combining values in any way. Processes other than those described above will be considered for inclusion in this

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			standard. Persons who wish to have other processes included shall submit, as a minimum, the following information for the committee's consideration:
MSS SP-25	1998	Standard marking system for valves, fittings, flanges and unions.	American standard by Manufacturers Standardization Society for valve, fitting, flange and union.
MSS SP-44	1996	Steel pipeline flanges.	American standard by Manufacturers Standardization Society for steel pipeline flange.
MSS SP-75	2008	Specification for high-test, wrought, butt-welding fittings	Covers factory-made, seamless and electric welded carbon and low alloy steel, butt-welding fittings for use in high pressure gas and oil transmission and distribution systems, including pipelines, compressor stations, metering and regulating stations, and mains. Governs dimensions, tolerances, ratings, testing, materials, chemical and tensile properties, heat treatment, notch toughness properties, manufacture and marking for high-test, butt-welding fittings NPS 60 and smaller. Dimensional requirements for NPS 14 and smaller are provided by reference to ASME B16.9. The term "welding fittings" applies to buttwelding fittings such as elbows, segments of elbows, return bends, caps, tees, single or multiple-outlet extruded headers, reducers, and factory-welded extensions and transition sections.(1) Fittings may be made to special dimensions, sizes, shapes, and tolerances, or of wrought materials other than those covered by this Standard Practice by agreement

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			between the manufacturer and the purchaser. When such fittings meet all other stipulations of this Standard Practice they shall be considered as being in partial compliance there with, providing they are appropriately marked. Fittings manufactured in partial compliance, as provided in Section 1.4, shall be identified with "Part" following the respective grade designation.
AS 2885	2003	A modern standard for design, construction, operation and maintenance of high integrity petroleum pipelines.	The suite of Standards that makes up the Australian Standard AS2885 "Pipelines – Gas and liquid petroleum" has been benchmarked against equivalent international and national Standards including ASME B31.8, CSA Z662, ISO 13623, API 1104, and ISO 13847. The benchmarking shows that AS2885 is superior in many detailed technical respects to its counterparts elsewhere, and that it better represents the current international state of the art in the design, construction, testing, operation and maintenance of petroleum pipelines. It is accepted by all of the stakeholders as the single and sufficient set of technical requirements . It uses an integral risk assessment and threat mitigation process in design and for the whole of the life of the pipeline in operation and maintenance. It has explicit requirements for the design, documentation, and approval of key processes such as prevention of external interference, control of fracture, and welding procedure qualification. And it assigns responsibility for the key processes to

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			suitably qualified, experienced, and trained people who take responsibility for their actions in writing. Amongst other reasons that has allowed the development of a worlds best practice Standard in Australia is the relatively small and agile committee process, and the involvement of many of the key contributors to the Standard in industry sponsored research projects. This involvement has simultaneously ensured that they are abreast of the latest developments, and that they are able to incorporate those developments in the Standard as and when they happen.
CSA Z662	2011	Oil and gas pipeline systems	The 2011 edition of CSA Z662 provides guidance in the design, operation and maintenance of Canada's oil and gas pipeline systems. The sixth edition addresses relevant industry changes related to legislation, regulation, management systems and technology. It is a Canadian national standard and is incorporated in federal and provincial pipeline safety legislation.
CSA Z245.20	2002	External fusion bonded epoxy coating for steel pope	This Standard covers the qualification, application, inspection, testing, handling, and storage of materials required for plant-applied fusion bond epoxy (FBE) coating applied externally to bare steel pipe. The coated pipe is intended primarily for buried or submerged service for oil or gas pipeline systems. This Standard does not cover dual powder FBE coating systems or high temperature (a glass transition temperature higher than 110 °C) FBE coating systems.
BS 4164	2002	Specification for coal tar based hot	Coatings, Protective coatings, Corrosion

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		applied coating materials for protecting iron and steel , including a suitable primer	protection, Primers (paint), Coal tar, Coal products, Fillers, Packaging, Marking, Sampling methods, Determination of content, Volatile matter determination, Density, Test equipment, Testing conditions, Softening point, Softening-point determination, Penetration tests, Viscosity, Sag (deformation), Cracking, Bend testing, Specimen preparation, Impact testing, Peeling tests, Mechanical testing, Low-temperature testing, Viscosity measurement, Density measurement, Grades (quality), Adhesion tests, Ignition-loss tests, Distillation methods of analysis
BS 5353	1989	Specification for steel plug valves	Design, materials, dimensions, pressure/temperature ratings, wall thicknesses, testing and marking of lubricated, and soft seated and lined valves. Gives requirements for anti-static features plus the option of a fire tested design.
BS 6651	1999	Code of practice for the protection of structures against lightning	This British Standard provides guidance on the design of systems for the protection of structures against lightning and on the selection of materials. Recommendations are made for special cases such as explosives stores and temporary structures, e.g. cranes and spectator stands constructed of metal scaffolding. Guidance is also provided on the protection of electronically stored data. This British Standard outlines the general technical aspects of lightning, illustrating its principal electrical, thermal and mechanical effects. Guidance is provided on how to assess the risk of being struck and how to compile an index figure as an aid to deciding whether a particular structure is in need of

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			protection.
BS 7430	1998	Code of practice for earthing	This British Standard gives guidance on the methods that may be adopted to earth an electrical system for the purpose of limiting the potential (with respect to the general mass of the earth) of current-carrying conductors forming part of the system, and non-current-carrying metalwork associated with equipment, apparatus, and appliances connected to the system. This standard applies only to land-based installations; it does not apply to ships, aircraft or offshore installations, nor does it deal with the earthing of medical equipment or the special problems encountered with solid state electronic components and equipment due to their sensitivity to static electricity.
BS PD8010	2009	Code of practice for pipelines	PD 8010-2:2004 gives recommendations for and guidance on the design, use of materials, construction, installation, testing, commissioning and abandonment of carbon steel subsea pipelines in offshore, nearshore and landfall environments. Guidance on the use of flexible composite pipelines is also given. It is not intended to replace or duplicate hydraulic, mechanical or structural design manuals. This part of PD 8010 is applicable to subsea pipelines intended for the conveyance of hydrocarbon liquids, hydrocarbon gases and other gases, liquids and gases in two-phase flow, fluid-based slurries and water. UK standard.
49 CFR 195	2012	Transportation of hazardous liquid by pipeline	US federal regulation This part prescribes safety standards and

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			reporting requirements for pipeline facilities used in the transportation of hazardous liquids or carbon dioxide.
NFPA 30	2008	Flammables and combustible liquids code.	This code shall apply to the storage, handling, and use of flammable and combustible liquids, including waste liquids, as herein defined and classified. 1.1.2 This code shall not apply to the following: (1)* Any liquid that has a melting point of 100°F (37.8°C) or greater (2)* Any liquid that does not meet the criteria for fluidity given in the definition of liquid in Chapter 3 and in the provisions of Chapter 4 (3) Any cryogenic fluid or liquefied gas, as defined in Chapter 3 (4)* Any liquid that does not have a flash point, but which is capable of burning under certain conditions (5)* Any aerosol product (6) Any mist, spray, or foam (7)* Transportation of flammable and combustible liquids as governed by the U.S. Department of Transportation (8)* Storage, handling, and use of fuel oil tanks and containers connected with oil-burning equipment A.1.1.1 This code is recommended for use as the basis for legal regulations. Its provisions are intended to reduce the hazard to a degree consistent with reasonable public safety, without undue interference with public convenience and necessity, of operations that require the use of flammable and combustible liquids. Compliance with this code does not eliminate all hazards in the use of flammable and combustible liquids. (See the Flammable and Combustible Liquids Code Handbook for additional explanatory information.) A.1.1.2(1) Liquids that are solid at 100°F

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			(37.8°C) or above, but are handled, used, or stored at temperatures above their flash points, should be reviewed against pertinent sections of this code. A.1.1.2(2) The information in A.1.1.2(1) also applies here. A.1.1.2(4) Certain mixtures of flammable or combustible liquids and halogenated hydrocarbons either do not exhibit a flash point using the standard closed-cup test methods or will exhibit elevated flash points. However, if the halogenated hydrocarbon is the more volatile component, preferential evaporation of this component can result in a liquid that does have a flash point or has a flash point that is lower than the original mixture. In order to evaluate the fire hazard of such mixtures, flash point tests should be conducted after fractional evaporation of 10, 20, 40, 60, or even 90 percent of the original sample or other fractions representative of the conditions of use. For systems such as open process tanks or spills in open air, an open-cup test method might be more appropriate for estimating the fire hazard. A.1.1.2(5) See NFPA 30B, Code for the Manufacture and Storage of Aerosol Products. A.1.1.2(7) Requirements for transportation of flammable and combustible liquids can be found in NFPA 385, Standard for Tank Vehicles for Flammable and Combustible Liquids, and in the U.S. Department of Transportation's Hazardous Materials Regulations, Title 49, Code of Federal Regulations, Parts 100–199. A.1.1.2(8) See NFPA 31, Standard for the Installation of Oil-Burning Equipment.

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NFPA 220	2012	Standard on types of building construction.	This standard defines types of building construction based on the combustibility and the fire resistance rating of a building's structural elements. Fire walls, nonbearing exterior walls, nonbearing interior partitions, fire barrier walls, shaft enclosures, and openings in walls, partitions, floors, and roofs are not related to the types of building construction and are regulated by other standards and codes, where appropriate.

Chapter-5. Reference Japanese Technical Standards

The reference Japanese industrial standards for designing oil fuel handling facility are organized in Table-20.

Table- 20: Reference Japanese Technical Standards

Number	Rev.	Title	Content
JIS G3476	2011	Petroleum and natural gas industries—Steel pipe for pipeline transportation systems	This stipulates about seamless steel pipe and welded steel pipe products (Grade PSL1 and PSL2) used for transportation in oil and gas industry.
JIS Z3050	2010	Method of nondestructive examination for weld of pipeline	This stipulates the non-destructive testing methods of for circumferential butt weld joint with its diameter is more than 100mm and less than 2,000mm, with its thickness more than 6mm and less than 40mm for the pipeline to transport oil and gas by using pipe in normal operation pressure 0.98MPa and more.
JIS Z2300	2008	Terms and definitions of nondestructive	This stipulates major terms and definitions used in industrial non-destructive testing.
JIS Z2306	2009	Radiographic image quality indicators for non-destructive testing	This stipulates about penertometer to be used for X-ray or γ-ray radiographic testing.
JIS Z2343-1	2010	Non-destructive testing － Penetrant testing－Part 1 : General principles－Method for liquid penetrant testing and classification of the penetrant indication	This stipulates penetrant testing method and classification method of indication patterns which is used detect crack opening the surface such as crack, overlapping, wrinkles, porosity and incomplete fusion.
JIS Z2343-2	2006	Non-destructive testing---Penetrant testing—Part2: Testing of penetrant materials	This stipulates technical requirement for type testing and lot testing of liquid penetrant, procedure of testing, management and method on site.
JIS Z2343-3	2010	Non-destructive testing---Penetrant testing—Part3: Reference test blocks	This stipulates 3 types of specimen of comparison tests. Type-1 is used to determine the sensitivity levels of both penetrant and fluorescent dye penetrant

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			products. Type-2 and 3 specimens are used to periodically examine the performance of equipment and agents for penetrant and fluorescent dye penetrant.
JIS Z2343-4	2010	Non-destructive testing---Penetrant testing—Part4: Equipment	This stipulates the characteristics of test equipment used for liquid penetrant examination.
JIS Z2345	2010	Standard test blocks for ultrasonic testing	This stipulates the standard specimens which is used to calibration, adjustment of ultrasonic test equipment and the sensitivity adjustment.
JIS Z3060	2011	Method for ultrasonic examination for welds of ferritic steel	This stipulates detection method, measurement of location and dimension defects of the full penetrated weld for ferritic steel with more than 6mm thickness by ultrasonic test using pulse-echo technique by manual.
JIS Z3104	2010	Methods of radiographic examination for welded joints in steel	This stipulates the radiographic transmission testing of steel welding joint by direct shooting method and by using X-ray or γ-ray using industrial X-ray film.
JIS Z4560	2008	Industry γ-ray apparatus for radiography	This stipulates about industrial γ-ray equipment used for γ-ray transmission testing.
JIS Z4561	2008	Viewing illuminators for industrial radiograph	This stipulates industrial observation instruments for grading of radiographic photos obtained by X-ray or γ-ray transmission testing.
JIS Z4606	2000	Industrial---X-ray apparatus for radiographic testing	This stipulates about industrial X-ray equipment used for X-ray transmission testing.
JIS K2251	2007	Crude petroleum and petroleum products---Sampling	This stipulates method to sample specimens of crude oil, petroleum products, semi-finished products, residue in the tank and sediment from static tank, tank lorry, drum, oil tanker, barge and pipeline.

Chapter-6. Reference TCVN

The reference Vietnamese national standards for designing oil fuel handling facility are organized in Table-21.

Table- 21: Reference TCVN

Number	Rev.	Title	Content
TCVN 3745-1	2008	Technical drawings. Simplified representation of pipelines. Part 1: General rules and orthogonal	Tiêu chuẩn này quy định quy tắc và quy ước biểu diễn các bản vẽ đơn giản các loại ống và đường ống được chế tạo bằng các loại vật liệu.
TCVN 3745-2	2008	System for design documentation. Rules of making drawings of pipes, pipelines and pipe line systems	Lập những quy tắc lập bản vẽ ống, đường ống và hệ thống đường ống nằm trong bộ tài liệu thiết kế của sản phẩm thuộc tất cả các ngành công nghiệ
TCVN 4090	1985	Main pipelines for transporting oil and oil products. Design standard	Ap dụng khi thiết kế mới, thiết kế cải tạo, phục hồi và mở rộng các công trình đường ống chính dẫn dầu và sản phẩm dầu và đường ống nhánh bằng thép có đường kính không lớn hơn 1400 mm
TCVN 4606	1988	Main pipeline used for transportation of petrol and petrol products. Rules for implementation and acceptance	Ap dụng để thi công và nghiệm thu các đường ống chính và đường ống nhánh bằng thép có đường kính không lớn hơn 1000 mm, có áp suất bơm chuyển không lớn hơn 1000 N/cm2, dùng để vận chuyển dầu mỏ, sản phẩm dầu mỏ và khí đốt
TCVN 5066	1990	Underground pipelines transferring gases, petroleum and petroleum products. General requirements for design and corrosion protection	áp dụng cho việc thiết kế mới phục hồi cải tạo, mở rộng đường ống chính dẫn khí đốt, dầu mỏ và sản phẩm dầu mỏ đặt ngầm dưới đất
TCVN 5422	1991	System of design documents. Symbols of pipelines	Qui định ký hiệu qui ước và đơn giản của đường ống và các phần tử của đường ống
TCVN 6022	2008	Petroleum liquids. Automatic pipeline sampling	Qui định các qui trình lấy mẫu tự động để nhận được các mẫu đại diện của dầu thô và các sản phẩm dầu mỏ lỏng chuyên chở đường ống

Number	Rev.	Title	Content
TCVN 6475-1	2007	Rules for Classification and Technical Supervision of Subsea Pipeline Systems. Part 1: General Requirement	Tiêu chuẩn này quy định các yêu cầu về phân cấp và giám sát kỹ thuật trong quá trình thiết kế, chế tạo và khai thác các hệ thống đường ống biển, kể cả các hệ thống đường ống đặt ở các cửa sông và vùng biển Việt Nam dùng để vận chuyển riêng lẻ hoặc hỗn hợp các chất hydrô cácbon ở trạng thái lỏng hoặc khí, như dầu thô, các sản phẩm của dầu, các loại khí.
TCVN 6475-2	2007	Rules for Classification and Technical Supervision of Subsea Pipeline Systems. Part 2: Classification of Subsea Pipeline Systems	Tiêu chuẩn này quy định các yêu cầu về phân cấp và giám sát kỹ thuật trong quá trình thiết kế, chế tạo và khai thác các hệ thống đường ống biển, kể cả các hệ thống đường ống đặt ở các cửa sông và vùng biển Việt Nam dùng để vận chuyển riêng lẻ hoặc hỗn hợp các chất hydrô cácbon ở trạng thái lỏng hoặc khí, như dầu thô, các sản phẩm của dầu, các loại khí.
TCVN 6475-3	2007	Rules for Classification and Technical Supervision of Subsea Pipeline Systems. Part 3: Requalification	Tiêu chuẩn này quy định các yêu cầu về phân cấp và giám sát kỹ thuật trong quá trình thiết kế, chế tạo và khai thác các hệ thống đường ống biển, kể cả các hệ thống đường ống đặt ở các cửa sông và vùng biển Việt Nam dùng để vận chuyển riêng lẻ hoặc hỗn hợp các chất hydrô cácbon ở trạng thái lỏng hoặc khí, như dầu thô, các sản phẩm của dầu, các loại khí.
TCVN 6475-4	2007	Rules for Classification and Technical Supervision of Subsea Pipeline Systems. Part 4: Design Philosophy	Tiêu chuẩn này quy định các yêu cầu về phân cấp và giám sát kỹ thuật trong quá trình thiết kế, chế tạo và khai thác các hệ thống đường ống biển, kể cả các hệ thống đường ống đặt ở các cửa sông và vùng biển Việt Nam dùng để vận chuyển riêng lẻ hoặc hỗn hợp các chất hydrô cácbon ở trạng thái lỏng hoặc khí, như dầu thô, các sản phẩm của dầu, các loại khí. Tiêu chuẩn này đưa ra các quy định về các nguyên tắc thiết kế một hệ thống đường ống biển.
TCVN 6475-5	2007	Rules for Classification and Technical	Tiêu chuẩn này quy định các yêu cầu mấu

Number	Rev.	Title	Content
		Supervision of Subsea Pipeline Systems. Part 5: Design Premises	chốt, cần thiết trong việc thiết kế, lắp đặt, vận hành và chứng nhận lại các hệ thống đường ống biển.
TCVN 6475-6	2007	Rules for Classification and Technical Supervision of Subsea Pipeline Systems. Part 6: Loads	Tiêu chuẩn này đưa ra các quy định về điều kiện tải trọng và hiệu ứng tải trọng đặc trưng được sử dụng trong thiết kế các hệ thống đường ống biển tỏng cả giai đoạn xây lắp và giai đoạn vận hành.
TCVN 6475-7	2007	Rules for Classification and Technical Supervision of Subsea Pipeline Systems. Part 7: Design Criteria	Tiêu chuẩn này quy định các chỉ tiêu thiết kế và các chỉ tiêu chấp nhận các dạng phá huỷ kết cấu có thể xảy ra đối với hệ thống đường ống biển.
TCVN 6475-8	2007	Rules for Classification and Technical Supervision of Subsea Pipeline Systems. Part 8: Linepipe	Tiêu chuẩn này quy định các yêu cầu đối với vật liệu, quá trình chế tạo, thử nghiệm và hồ sơ của hệ thống đường ống về các tính chất đặc trưng của vật liệu sau khi nhiệt luyện, giãn nở và tạo dáng lần cuối.
TCVN 6475-9	2007	Rules for Classification and Technical Supervision of Subsea Pipeline Systems. Part 9: Component and Assemblies	Tiêu chuẩn này quy định những yêu cầu về thiết kế, chế tạo, lắp đặt, thử nghiệm và hồ sơ của các bộ phận đường ống và các hạng mục kết cấu. Ngoài ra, tiêu chuẩn này còn quy định những yêu cầu về chế tạo và thử nghiệm các ống đứng, các vòng dãn nở, các đoạn ống dùng để cuộn ống và kéo ống.
TCVN 6475-10	2007	Rules for Classification and Technical Supervision of Subsea Pipeline Systems. Part 10: Corrosion Protection and Weight Coating	Phạm vi áp dụng của phần này bao gồm chống ăn mòn bên trong và bên ngoài đường ống và ống đứng cũng như lớp bọc bê tông gia tải để chống nổi đường ống.
TCVN 6475-11	2007	Rules for Classification and Technical Supervision of Subsea Pipeline Systems. Part 11: Installation	Tiêu chuẩn này được áp dụng cho việc lắp đặt và kiểm tra các đường ống và ống đứng cứng được thiết kế và chế tạo theo các yêu cầu cảu tiêu chuẩn này.
TCVN 6475-12	2007	Rules for Classification and Technical Supervision of Subsea Pipeline Systems. Part 12: Weldings	Tiêu chuẩn này áp dụng cho tất cả các quá trình chế tạo trong xưởng hoặc ngoài hiện trường, bao gồm cả quá trình xử lý nhiệt sau khi hàn.

Number	Rev.	Title	Content
TCVN 6475-13	2007	Rules for Classification and Technical Supervision of Subsea Pipeline Systems. Part 13: Non Destructive Testing	Tiêu chuẩn này quy định các yêu cầu đối với các phương pháp, thiết bị, quy trình, chỉ tiêu chấp nhận, chứng nhận các chứng chỉ cho các nhân sự thực hiện kiểm tra bằng mắt thường và kiểm tra không phá huỷ (NDT) vật liệu thép C-Mn, thép duplex, các loại thép không gỉ khác và các vật liệu thép có lớp phủ chống ăn mòn, các đường hàn được sử dụng trong các hệ thống đường ống.

Chapter-7. Referenced Literature and Materials

The referenced books, literatures, standards to establishing this guide line are organized as follows.

1. Interpretation of technical regulation for thermal power facility (10/Jul/1007): NISA (Nuclear and Industrial Safety Agency) of METI (Ministry of Economy, Trade and Industry Japan)
2. Regulation for the transportation and handling station of hazardous materials (Dec/2011): Ministry of Internal Affairs and Communications Japan)
3. Fuel and combustion (No.588: Sept/2005): TENPES (Thermal and Nuclear Engineering Society of Japan)
4. The outline—boiler (No.583: Apr/2006): TENPES (Thermal and Nuclear Engineering Society of Japan)
5. Fuel and combustion (Sept/2006): TENPES (Thermal and Nuclear Engineering Society of Japan)
6. Fuel receiving and storage facility (No.516: Sept/1999): TENPES (Thermal and Nuclear Engineering Society of Japan)
7. ISO 13623-2000 Petroleum and natural gas industries— Pipeline transportation systems